VIII. State Plans

A. Overview

After the EPA establishes the emission guidelines, each state[1] shall then develop, adopt and submit a state plan under CAA section 111(d). Each state's obligation under section 111(d) and under these guidelines is to establish a standard of performance for the affected EGUs in its jurisdiction in order to implement the BSER. That standard of performance may expressly incorporate the CO_2 emission performance rates the EPA has set forth in these guidelines to express the BSER, or, as an alternative, the state may establish standards of performance at different levels for different EGUs. As a second alternative, the state may adopt measures apart from or in addition to standards of performance for its affected EGUs. These guidelines include rate-based and mass-based CO_2 emission goals for each state that represent the equivalent in aggregate of the CO_2 emission performance rates applied to the affected EGUs in each state; states that adopt either of the two alternative approaches – differential standards of performance among their affected EGUs or "state measures" - must demonstrate that, in the aggregate, the differential standards of performance and/or measures they adopt will result in their affected EGUs meeting in the aggregate

[1] In this section, the term "state" encompasses the 50 states and the District of Columbia, U.S. territories, and any Indian tribe that has been approved by the EPA pursuant to 40 CFR 49.9 as eligible to develop and implement a CAA section 111(d) plan.

either the states' respective rate-based CO_2 emission goals or mass-based CO_2 emission goals. The EPA believes that it is appropriate to allow states this significant flexibility in both the timing and location of emission reductions because CO_2 is a global pollutant, and where and when the reductions occur is not as significant to the environmental outcome as compared to many other conventional pollutants.

Each state must decide whether to adopt a plan to meet the CO_2 emission performance rates for affected EGUs – either as emission standards for each EGU reflecting the CO_2 emission performance rates that represent BSER or as emission standards differentiated among its affected EGUs – or to meet, in the rate-based metric or in the mass-based metric, the CO_2 emission goals set forth by the EPA for the state. As already stated, the EPA is establishing goals for each state in order to ensure both that states and affected EGUs enjoy the maximum flexibility and latitude in meeting the requirements of the emission guidelines and that the BSER is fully implemented by each state. For its plan, a state will be able to choose to either impose federally enforceable emission standards that fully meet the emission guidelines directly on affected EGUs (the "emission standards" approach) or use a "state measures" approach, which would comprise, at least in part, measures implemented by the state that are not included as federally enforceable components of the plan, with a backstop of federally enforceable standards on affected EGUs that fully meet the emission guidelines and that would be triggered if the state measures fail to result in the affected EGUs achieving on schedule the required emissions reductions.

In developing the plan, the state rulemaking process must meet the minimum public participation requirements of these guidelines, including a public hearing and meaningful engagement with all members of the public, including affected communities. Within the time period specified in the emission guidelines (from as early as August 31, 2016, to as late as August 31, 2018, depending on whether the state receives an extension), the state must submit its final state plan to the EPA. The EPA then must determine whether to approve or disapprove the plan. If a state does not submit a plan, or if the EPA disapproves a state's plan, then the EPA has the express authority under CAA section 111(d) to establish a federal plan for the state. During and following implementation of its plan, each state must demonstrate to the EPA that its affected EGUs are meeting the interim and final performance requirements included in this final rule through monitoring and reporting requirements.

In the case of a tribe that has one or more affected EGUs located in its area of Indian country, if the tribe either does not submit a CAA section 111(d) plan or does not receive EPA approval of a submitted plan, the EPA has the responsibility to establish a CAA section 111(d) plan for that area if it determines that such a plan is necessary or appropriate to protect air quality.[2]

This section is organized as follows. First, we discuss the state plan performance periods. Second, we describe the types of plans that states can submit. Third, we summarize the components of an approvable state plan submittal. Fourth, we address the process and timing for submittal of state plans and plan revisions. Fifth, we address plan implementation and achievement of CO_2 emission performance rates or state CO_2 emission goals for affected EGUs, and the consequences if they are not met. Sixth, we discuss general considerations for states in developing and implementing plans, including consideration of a facility's "remaining useful life" and "other factors" and electric reliability. Seventh, we note certain resources that are available to facilitate state plan development and implementation. Finally, we discuss additional considerations for inclusion of CO_2 emission reduction measures in state plans, including: accounting for emission reduction measures in state plans; requirements for rate-based emission trading approaches; evaluation, measurement, and verification (EM&V) criteria for RE and demand-side EE resources used to adjust a CO_2 rate; and treatment of interstate effects.

B. State Plan Performance Periods

This section describes state plan requirements related to

[2] See 40 CFR 49.1 to 49.11.

the timing of achieving the emission guidelines and state plan performance periods. A performance period is a period for which the final plan submittal must demonstrate that the required CO_2 emission performance rates or state CO_2 emission goal will be met. The EPA received significant and diverse comments on both the start date of the interim period and the trajectory of compliance over the interim period. After careful consideration of those comments, we are finalizing a start date of January 1, 2022 for the interim period, and three interim step periods.

As previously discussed, the EPA has determined that the BSER includes implementation of reduction measures over the period of 2022 through 2029, with final compliance in 2030. Therefore the final rule requires that interim CO_2 emission performance rates or state CO_2 emission goals be met for the interim period of 2022-2029, and for the three interim step periods (2022-2024, 2025-2027, 2028-2029). The final rule allows states that choose to meet a state CO_2 emission goal the flexibility to define an alternate trajectory of emission performance between 2022 and 2029 to the steps specified in the rule. States have the option of meeting goals of the state's choosing for the interim step periods instead of meeting the interim step goals provided in the emission guidelines, as long as meeting the state-determined interim step goals will still result in the interim state CO_2 emission goal being met on an 8-year average or cumulative basis and the 2030 state CO_2 emission goal is achieved. To be approvable, a state plan submittal must demonstrate that the emission performance of affected EGUs will meet the interim step CO_2 emission performance rates or state CO_2 emission interim step goals on average over the 2022-2024, 2025-2027, and 2028-2029 periods and the final CO_2 emission performance rates or state CO_2 emission goal no later than 2030.

This relatively long planning and implementation period provides states with substantial flexibility regarding methods and timing of achieving emission reductions. States may wish to make adjustments to their implementation approaches along the way, or as conditions change, may need to make adjustments to ensure that their plans achieve the CO_2 emission performance rates or state CO_2 emission goals as intended. As a result, the agency envisions that the EPA, states and affected EGUs will have an ongoing relationship in the course of implementing this program. The EPA believes that timing flexibility in implementing measures provides significant benefits that allow states to develop plans that will help achieve a number of goals, including, but not limited to: reducing cost, addressing reliability concerns and addressing concerns about stranded assets.

The EPA received numerous comments regarding the concept of the interim compliance period, including comments supporting the flexibility afforded states in developing their plans and the timing necessary to meet the 2030 emission requirements. Some commenters supported beginning the interim goal program at 2020. Others stated that the investments necessary to meet the proposed 2020 reduction goals are unachievable in that timeframe or would place too great a burden on affected EGUs and states. Some suggested that the 2020 interim goal step should be eliminated in favor of later start dates, including 2022, 2025, or other years. Other commenters provided input suggesting that states be allowed to establish their own set of interim guidelines and thereby control their own glide path toward the 2030 goal. As discussed in previous sections, based on comments received, the EPA has adjusted the start date for the interim period to 2022, and is retaining the flexibility for states to establish their own emissions trajectory during the interim period. Because of the additional time provided before the beginning of the interim plan performance period, the EPA has determined that additional assurance that states are making progress in implementing the plan between the time of the state plan submittal and the beginning of the interim period is appropriate. As discussed in detail in section VIII.D, the final rule requires that the state plan submittal include a timeline with all the programmatic milestone steps the state will take between the time of the state plan submittal and 2022 to ensure the plan is effective as of 2022. States must submit a report to the EPA in 2021 that demonstrates that the state has met the programmatic milestone steps that the state indicated it would take from the submittal of the final plan through the end of 2020, and that the state is on track to implement the approved state plan as of January 1, 2022. If the EPA approves a state plan that includes the required obligation on the state to submit this report, and the state either does not submit the requisite report by July 1, 2021, or the state submits a report demonstrating it has not met the programmatic milestones, the EPA's approval of the state plan will convert to a disapproval. Per the requirements of CAA section 111(d), the EPA will develop and implement a federal plan in the instance of such disapproval.

Many commenters supported providing incentives for states to deploy CO_2-reducing investments, such as RE and demand-side EE measures, as early as possible. The EPA recognizes the value of such early actions, and in this final rule is providing states with discretion to credit reductions from the activities, implemented from 2013 onward, in the context of both mass-based and rate-based plans. If a state demonstrates, in its July 1, 2021 report, that it has implemented such early action measures, the EPA will consider its report to be presumptively approvable. See sections VIII.C and VIII.G for a discussion of state plan requirements related to incentivizing early action under mass-based and rate-based plans, respectively.

The EPA has based its determination of the BSER on reductions that are achievable beginning in 2022. For that reason, these guidelines require no reductions to be made by affected EGUs prior to 2022 or by other entities in those states that adopt a state measures plan. At the same time, the EPA has concluded that it is essential to the achievement in a timely and cost-effective way of the emissions reductions required to meet the CO_2 emission performance rates or, in the alternative, the state goals, that the states and EGUs are rewarded for undertaking investments that yield reductions in the years prior to 2022. Accordingly, state plans must include a mechanism to ensure this outcome.

For purposes of meeting this requirement, a state plan would be presumptively approvable if it included provisions comprising one of the following elements:

- A commitment to demonstrating plan performance on the basis of averaging its emissions over a 10-year period beginning with emissions from its affected EGUs in 2020, factoring in the state's projected business as usual emissions (rates) in 2020 and 2021.
- A mechanism for awarding to affected EGUs allowances or credits for reductions that would contribute to the state's achievement of reductions in 2020 and 2021 that are below its business as usual projected emissions for each of those years, and provided that the state's emissions in 2020 and 2021 not exceed the state's projected business as usual level.

Nothing in these provisions would have the effect of requiring any particular affected EGU to achieve reductions prior to 2022. In addition, states would have the option for including in their state plans mechanisms as alternatives to those described above for meeting the overall emissions reduction requirements for 2020 and 2021, provided that any state submitting a plan that included a mechanism as an alternative to the presumptively approvable mechanism(s) described above could demonstrate that the alternative would achieve the same outcome as the mechanism(s) described above.

The EPA is including this state plan requirement for several reasons. Chief among them are those offered by commenters to the effect that the overall cost of achievement of the state goals could be reduced by an approach that granted some form of beneficial recognition to emissions reduction investments that both occur and yield reductions prior to the first date on which the program mandates reductions or imposes emissions limitations. Other commenters pointed out that to the extent that states and utilities would benefit from the availability of low-cost RE and other zero-emitting generation options during the interim and final periods, the EPA should include in the final guidelines provisions that accelerate deployment of RE resources, since in so doing the program would speed achievement of expected reductions in the cost of those technologies commensurate with their accelerated deployment.

C. State Plan Approaches

1. Overview

Under the final emission guidelines, states may adopt and submit either of two different types of state plans. The first would apply all requirements for meeting the emission guidelines to affected EGUs in the form of federally enforceable emission standards,[3] which we refer to as an "emission standards" state plan type. The second, which we refer to as a "state measures" plan type, would allow the CO_2 emission performance rates or state CO_2 emission goals to be achieved in part, or entirely, through state measures[4] that apply to affected EGUs, other entities, or some combination thereof. The state measures plan type also includes a mandatory contingent backstop of federally enforceable emission standards for affected EGUs that would apply in the event the plan does not achieve its anticipated level of emission performance during the period that the state is relying on state measures. The inclusion of a backstop of federally enforceable measures is legally necessary for a state to meet the requirements of 111(d), which specifically requires a state to submit standards of performance, if the state chooses to adopt the state measures plan type.

These two types of state plans and their respective

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[3] 40 CFR 60.21(f) defines "emission standard" as "a legally enforceable regulation setting forth an allowable rate of emissions into the atmosphere, establishing an allowance system, or prescribing equipment specifications for control of air pollution emissions."

[4] "State measures" refer to measures that the state adopts and implements as a matter of state law. Such measures are enforceable only per state law, and are not included in and codified as part of the federally enforceable state plan.

approaches, either of which could be implemented on a single-state or multi-state basis, allow states to meet the statutory requirements of CAA section 111(d) while accommodating the wide range of regulatory requirements and other programs that states have deployed or will deploy in the electricity sector that reduce CO_2 emissions from affected EGUs. Further, as described in detail below, both types of plans are responsive to comments we received from states and other stakeholders.

In addition to providing states the option of developing an emission standards or state measures type plan, the final rule makes clear that states can adopt either a rate-based or mass-based CO_2 emission goal. Further, the EPA notes that for either an emission standards plan or a state measures plan, if a state chooses the option of meeting a state rate or mass CO_2 emission goal, the metric chosen for the goal is independent from the measures that implementing authorities may adopt to achieve them. For example, a state could potentially adopt mass-based emission standards and/or other measures and demonstrate that its plan will achieve a rate-based CO_2 goal. Likewise, a state could adopt rate-based emission standards and/or other measures and demonstrate that its plan will meet a mass-based CO_2 goal.

2. “Emission standards” state plan approach

The first type of state plan imposes requirements solely on affected EGUs in the form of federally enforceable emission standards, which we refer to as an “emission standards” plan.

This type of state plan, as described below, may consist of rate-based emission standards for affected EGUs or mass-based emission standards for affected EGUs. Rate-based and mass-based emission standards may incorporate the use of emission trading, as described below.[5] The EPA anticipates the use of emission trading in state plans, due to the advantages of this approach.[6]

Under this approach, the state plan submittal must demonstrate that these federally enforceable emission standards for affected EGUs will achieve the state CO_2 emission goal or CO_2 emission performance rates or the applicable rate-based or mass-based state CO_2 emission goal.

a. Rate-based approach. The first type of "emission standards" plan approach a state may choose is one that uses rate-based emission standards. Under this plan approach, the plan would include federally enforceable emission standards for affected EGUs, in the form of lb CO_2/MWh emission standards.

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[5] The EPA notes it is proposing model rules for both mass-based and rate-based emission trading programs. States that adopt and submit the finalized model rules for either emission trading program will be presumptively approvable as meeting the requirements of CAA section 111(d) and these emission guidelines. States that adopt and submit the *proposed* model rule for either the mass-based or rate-based emission trading program would be presumptively approval through the conditional approval mechanism, which the EPA intends to adopt through the upcoming Federal Plan rulemaking. Under the conditional approval mechanism, states that adopt and submit the proposed model rule(s) would have an obligation to submit the model rule as finalized by the EPA, or the conditional approval of the state plan submission would convert to a disapproval.

[6] The legal basis for authorizing trading in emission standards is discussed in section VIII.C.3.d.

A rate-based "emission standards" plan may be designed to either meet the CO_2 emission performance rates for affected EGUs or achieve the state's rate-based CO_2 emission goal for affected EGUs. To meet the CO_2 emission performance rates, a plan would establish separate rate-based emission standards for affected fossil fuel-fired electric utility steam generating units and stationary combustion turbines (in lb CO_2/MWh) that are equal to or lower than the CO_2 emission performance rates in the emission guidelines. To meet a state rate-based CO_2 goal, a plan would establish a uniform rate-based emission standard (in lb CO_2/MWh) that applies to all affected EGUs in the state. This uniform emission rate would be equal to or lower than the applicable state rate-based CO_2 goal specified in the final emission guidelines.

Under these two approaches, compliance by affected EGUs with the rate-based emission standards in a plan would ensure that affected EGUs meet the CO_2 emission performance rates in the emission guidelines or the state rate-based CO_2 goal for affected EGUs. No further demonstration would be necessary by the state to demonstrate that its plan would achieve the CO_2 emission performance rates or the state's rate-based CO_2 goal.

If a state chose, it could instead apply rate-based emission standards to individual affected EGUs, or to categories of affected EGUs, at a lb CO_2/MWh rate that differs from the CO_2 emission performance rates or the state's rate-based CO_2 goal. In this case, compliance by affected EGUs with their emission standards would not necessarily ensure that the collective, weighted average CO_2 emission rate for these affected EGUs meets the CO_2 emission performance rates or the state's rate-based CO_2 goal.

Under this type of approach, the state would be required to include a demonstration,[7] in the state plan submittal, of how its plan would achieve the CO_2 emission performance rates or applicable state rate-based CO_2 goal. This demonstration would include a projection of the collective, weighted average CO_2 rate it anticipates the fleet of affected EGUs would achieve as a result of compliance with the emission standards in the plan. Once the plan is implemented, if the CO_2 emission performance rates or applicable state rate-based CO_2 goal are not achieved, corrective measures would need to be implemented, as described in section VIII.F.3.

Under a rate-based approach, a state may include in its plan a number of provisions to facilitate affected EGU compliance with the emission standards. First, a state may encourage (or require) EGUs to undertake actions to reduce CO_2 emissions at the source level, such as heat rate improvements or fuel switching. Second, a state may implement a market-based emission trading program, which enables EGUs to generate and procure Emission Rate Credits

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[7] A demonstration of how a plan will achieve a state's rate-based or mass-based CO_2 emission goal is one of the required plan components, as described in section VIII.D.2.

(ERCs), a tradable compliance unit representing one MWh of electric generation (or reduced electricity use) with zero associated CO_2 emissions. These ERCs would be issued by the administering state regulatory body.

The state may issue ERCs to affected EGUs that emit below a specified CO_2 emission rate, as well as for measures that provide substitute generation for affected EGUs or avoid the need for generation from affected EGUs. These ERCs may then be used to adjust the reported CO_2 emission rate of an affected EGU when demonstrating compliance with a rate-based emission standard. For each submitted ERC, one MWh is added to the denominator of the reported CO_2 emission rate, resulting in a lower adjusted CO_2 emission rate.

Eligible measures that may generate ERCs, as well as the accounting method for adjusting a CO_2 emission rate, are discussed in section VIII.G.1. Requirements for rate-based emission trading approaches are discussed in section VIII.G.3. Quantification and verification requirements for RE and demand-side EE programs and projects are discussed in section VIII.G.4.

ERCs issued in 2022 or a subsequent year may be carried forward (or "banked") and used for demonstrating compliance in a future year.[8] For example, an ERC issued for a MWh of RE

[8] States may also consider issuing ERCs representing MWh generation or savings that occur from 2013-2021. Requirements for including this type of a provision in a state plan are discussed in section VIII.G.1.b.(2).

generation that occurs in 2022 may be applied to adjust a CO_2 emission rate in 2023 or future years without limitation. ERCs may be banked from the interim plan performance period to the final plan performance period. Banking provides a number of advantages while ensuring that the same output-weighted average CO_2 emission rates of the interim and final state CO_2 goals are achieved over the course of a state plan. Banking provisions have been used extensively in rate-based environmental programs and mass-based emission budget trading programs.[9] This is because banking reduces the cost of attaining the requirements of the regulation. The EPA has determined that the same rationale and outcomes apply under a CO_2 emission rate approach, in that allowing banking will reduce compliance costs. Banking encourages additional emission reductions in the near-term if economic to meet a long-term emission rate constraint, which is beneficial due to social preferences for environmental improvements sooner rather than later.[10] Banking also provides long-term economic signals to

[9] Banking under mass-based emission budget trading programs, and the rationale for banking provisions, is addressed below in section VIII.C.3.b.(2)(a).

[10] The absence of banking creates an incentive to defer both relatively low-cost and higher-cost CO_2 emission reduction actions until a later period when emission rate limits become more stringent, rather than incentives to undertake the low-cost activities sooner in order to further delay the high cost actions. Under a rate-based emission trading program, banking will encourage ERC providers to generate larger numbers of ERCs in early years of a plan performance period, in anticipation of rising ERC prices over time, when demand for ERCs is expected to increase as rate-based CO_2 emission standards become more stringent.

affected emission sources and other market participants where actions taken today will have economic value in helping meet tighter emission constraints in the future, provided those emission sources expect that the banked emission rate credits or emission allowances may be used for compliance in the future. Linking short-term and long-term economic incentives, which allows owners or operators of affected EGUs and other market participants to assess both short-term and long-term incentives when making decisions about compliance approaches or emission reduction investments, reduces long-term compliance costs for affected EGUs and consumer price impacts. In addition, the increased temporal flexibility provided by banking would further help address potential electric reliability concerns, as banked ERCs can be used to meet emission standard requirements for an affected EGU.

b. Mass-based approach. The second "emission standards" approach a state may elect to use is mass-based emission standards applied to affected EGUs. Under this approach, the plan would include federally enforceable emission standards on mass CO_2 emissions from affected EGUs that are designed to achieve the mass-based CO_2 goal for a state's affected EGUs (see section VII). States could also apply mass emission standards on affected EGUs that are designed to achieve a state's rate-based goal.[11]

[11] Under this type of approach, the state would be required to include a demonstration, the state plan submittal, of how its plan would achieve the goal. This demonstration would include a

Under a mass-based approach, a state could require that individual affected EGUs meet a specified mass emission standard. Alternatively, a state could choose to implement a market-based emission budget trading program. The EPA envisions that the latter option is most likely to be exercised by states seeking to implement a mass-based emission standard approach, as it would maximize compliance flexibility for affected EGUs and enable the state to meet its mass goal in the most economically efficient manner possible.

(1) Mass-based emission standard applied to individual affected EGUs. One pathway a state could take to achieve its mass-based CO_2 goal would be to apply mass-based emission standards to individual affected EGUs, in the form of a limit on total allowable CO_2 emissions. These emission standards would be designed such that total allowable CO_2 emissions from all affected EGUs in a state are equal to or less than the state's mass-based CO_2 goal. The individual affected EGUs would be required to emit at or below their mass-based standard to demonstrate compliance. Under this approach, individual affected EGUs would be required to undertake source-specific measures to assure their CO_2 emissions do not exceed their assigned emission

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projection of the collective, weighted average CO_2 rate it anticipates the fleet of affected EGUs would achieve as a result of the mass emission limits placed on affected EGUs. Once the plan is implemented, if the rate goal is not achieved for the fleet of affected EGUs as a whole, corrective measures would need to be implemented, as described in section VIII.F.3.

limit. Affected EGU compliance with the emission standards prescribed under this type of mass-based approach would ensure that the affected EGUs in a state achieve the state's mass-based CO_2 goal.

(2) Mass-based emission standard with a market-based emission budget trading program. A second pathway a state could take to achieve its mass-based CO_2 goal would be to implement a market-based emission budget trading program. This type of program provides maximum compliance flexibility to affected EGUs, and as a result, may be attractive to states who choose to implement a mass-based approach in their state plan.

An emission budget trading program establishes a combined emission standard for a group of emission sources in the form of an emission budget. Emission allowances are issued in an amount up to the established emission budget.[12] Allowances may be distributed to affected emission sources through a number of different methods, including direct allocation to affected sources or auction. These allowances can be traded among affected sources and other parties. The emission standard applied to individual emission sources is a requirement to surrender emission allowances equal to reported emissions, with each allowance representing one ton of CO_2.

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[12] An emission allowance represents a limited authorization to emit, typically denominated in one short ton or metric ton of emissions.

The EPA notes it is proposing model rules for both mass-based and rate-based emission trading programs. States that adopt and submit the finalized model rules for the mass-based trading program will be presumptively approvable as meeting the requirements of CAA section 111(d) and these emission guidelines through adoption of mass-based emission standards with a market-based emission budget trading program.

(a) Emission budget trading programs that ensure achievement of a state CO_2 goal. Under the emission standards plan type, a mass-based emission budget trading program must be designed such that compliance by affected EGUs would achieve the state mass-based CO_2 goal. Under this approach, a state plan would establish emission budgets for affected EGUs during the interim and final plan performance periods that are equal to or lower than the applicable state mass-based CO_2 goals specified in section VII. Compliance periods for affected EGUs would also be aligned with the interim and final plan performance periods. This approach would limit total CO_2 emissions from affected EGUs during the interim and final plan performance periods to an amount equal to or less than the state's mass-based CO_2 goal.

Under this approach, compliance by affected EGUs with the mass-based emission standards in a plan would ensure that the state achieves its mass-based CO_2 goal for affected EGUs. No further demonstration would be necessary by the state to demonstrate that its plan would achieve the state's mass-based

CO_2 goal.

For this type of plan, where the emission budget is equal to or less than the state mass CO_2 goal,[13] the EPA would assess achievement of the state goal based on compliance by affected EGUs with the mass-based emission standards, rather than reported CO_2 emissions by affected EGUs during the interim plan performance periods and final plan performance periods. This approach would allow for allowance banking between performance periods, including the interim and final performance periods outlined in this final rule. This is a typical design element for emission budget trading programs addressing GHG emissions.

Allowing allowance banking across plan performance periods, including from the interim period to the final period, provides a number of advantages while ensuring that the same cumulative emission reductions are achieved over the course of a state plan. Emission budget trading programs with unlimited allowance banking limit cumulative tonnage emissions over the period in which they are applied. As a result, common program design is to allow allowance banking without limitation, unless there is an environmental reason for not doing so (e.g., for criteria pollutants where timing of emissions is important). As discussed in section VIII.C.3.a above, addressing banking under rate-based emission trading programs, this is because banking reduces the

[13] As specified for the interim plan performance period (including specified levels in interim steps 1 through 3) and the final two-year plan performance periods.

cost of attaining the requirements of the program. In addition, the increased temporal flexibility provided by allowance banking would further help address potential electric reliability concerns, as banked allowances can be used to meet emission limit requirements for an affected EGU.

(b) Addressing emission budget trading programs with broader source coverage and other flexibilities. As described in section VIII.C.3.b(2)(a) above, under the emission standards plan type, a mass-based emission budget trading program must be designed such that compliance by affected EGUs would achieve the state mass-based CO_2 goal. However, emission budget trading programs, including those currently implemented by California and the RGGI participating states, include a number of different design elements. If a state chose, it could apply mass-based emission standards in the form of an emission budget trading program that differs in design from that outlined in section VIII.C.3.b(2)(a) above. However, these types of emission budget trading programs must be submitted as a state measure, rather than incorporated as federally enforceable emission standards, as described below in section VIII.C.4.c.

(c) State plan provisions required for a mass-based emission budget trading program approach. For a mass-based emission trading program approach, the state plan would include as its federally enforceable emission standards requirements that specify the emission budget and related compliance requirements and mechanisms. These requirements would include: CO_2 emission monitoring, reporting, and recordkeeping requirements for affected EGUs; provisions for state allocation of allowances; provisions for tracking of allowances, from issuance through submission for compliance; and the process for affected EGUs to demonstrate compliance (allowance "true-up" with reported CO_2 emissions).

(d) Considerations for mass-based emission budget trading programs. The EPA notes that while an emission budget trading program included in an emission standards plan must be designed to achieve a state mass-based CO_2 goal, states have wide discretion in the design of such programs, provided the emission standards included in the plan are quantifiable, verifiable, enforceable, non-duplicative, and permanent.

A key example is state discretion in the CO_2 allowance allocation methods included in the program.[14] This includes the methods used to distribute CO_2 allowances and the parties to which allowances are distributed. For example, if a state chose, it could include CO_2 allowance allocation provisions that provide incentives for certain types of complementary activities, such as RE generation, that help achieve the overall CO_2 emission limit for affected EGUs established under the program. States could also use CO_2 allowance allocation provisions to provide

[14] Allowance allocation refers to the methods used to distribute CO_2 allowances to the owners or operators of affected EGUs and/or other market participants.

incentives for early action, such as RE generation or demand-side EE savings that occur prior to the beginning of the interim plan performance period in 2022. For example, a state could include CO_2 allowance allocation provisions where CO_2 allowances are distributed to RE generators based on MWh of RE generation that occurs prior to 2022. Such provisions might be addressed through a finite set-aside of CO_2 allowances that are available for allocation under these provisions.

c. Other EGU emission standard approaches. As discussed in further detail in section VIII.D.d.(3) regarding the legal issues and statutory language of CAA section 111(h), the EPA is finalizing that design, equipment, work practice, and operational standards cannot be considered as "standards of performance" for this final rule. However, the third "emission standards" approach a state may elect to use is emission standards for affected EGUs that result in reduced CO_2 lb/MWh or total tons of CO_2 affected EGUs because of operational or other standards. Under this approach, the state would include in its state plan an emission standard that is the rate or mass standard that results from the applicable operational or other standard. For example, a state might choose to recognize that an individual affected EGU has plans to retire, and those plans could be codified in the state plan by adopting an emission standard of 0 CO_2 lb/MWh, or 0 total tons, as of a certain date. The state would thus include in the state plan an emission standard of 0 CO_2 lb/MWh or 0 total tons for that affected EGU that applies after a specified date. Under a mass-based approach, the state could also include an emission standard (e.g., a mass limit) that reflects the result of a limit on an affected EGU's total operating hours over a specified period.

An approvable plan could apply such emission standards to a subset of affected EGUs or all affected EGUs. As with any plan, the state would need to demonstrate that the plan would achieve the required level of emission performance for affected EGUs, in either CO_2 lb/MWh or total tons of CO_2. A plan could also apply such emission standards to a subset of affected EGUs in the state while applying emission standards to the remainder of affected EGUs in the state. For example, a plan might include an emission standard of 0 CO_2 lb/MWh reflecting a retirement mandate for one or more affected EGUs in a state and apply a rate-based emission standard equal to the CO_2 emission performance rate or state's rate-based CO_2 emission goal to the remainder of affected EGUs.

As with the other two approaches, emission standards under this approach must be quantifiable, verifiable, enforceable, non-duplicative and permanent. These requirements are described in more detail at section VIII.D.2.

d. Legal basis for emission standards approach. The emission standards approach is consistent with the requirements of CAA section 111(d). If a state simply adopts the CO_2 emission performance rates, then the corresponding rate-based emission standards in the state plan establish standards of performance for affected EGUs as required under section 111(d)(1)(A). Similarly, if a state chooses to achieve the rate-based CO_2 emission goal through rate-based emission standards, or to achieve the mass-based CO_2 emission goal through mass-based emission standards, then the set of rate-based emission standards or the set of mass-based emission standards in the state plan establishes standards of performance for affected EGUs as required under section 111(d)(1)(A). In all three cases, the emission standards must be quantifiable, verifiable, enforceable, non-duplicative and permanent; this ensures that the plan provides for implementation and enforcement of the standards of performance (i.e. the emission standards) as required by section 111(d)(1)(B). Finally, as described in section VIII.B.7.b below, standards of performance may include emission trading. Thus, the credit and allowance trading that is allowed under the emission standards approach is consistent with the statutory requirement that the plan establish standards of performance.

e. Legal basis for emissions trading in state plans. There are three legal issues with respect to emissions trading in state plans. First, we explain how the definition of "standard of performance" in section 111(a)(1) allows section 111(d) plans to include standards of performance that authorize emissions trading. Second, we explain how the EPA interprets the phrase "provides for implementation and enforcement of [the] standards of performance” in the context of a rate-based ERC trading scheme. Third, we give a similar explanation of the EPA’s interpretation of the same phrase in the context of a mass-based allowance trading scheme.

(1) In the proposal, the EPA proposed that CAA section 111(d) plans may include standards of performance that authorize emissions averaging and trading. 79 FR 34830, 34927/1 (June 18, 2014). We are finalizing the use of emissions trading in this rule.

For purposes of this legal discussion, in the case of an emission limitation expressed as an emission rate, trading takes the form of buying or selling ERCs that an affected EGU may generate if its actual emission rate is lower than its allowed emission rate. In the case of an emission limitation expressed as a mass-based limit, trading takes the form of buying or selling allowances.

To reiterate for convenience, the definition of “standard of performance” under CAA section 111(a)(1) is:

> The term ‘standard of performance’ means a standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction and any nonair quality health and environmental impact and energy requirements) the

Administrator determines has been adequately demonstrated.

Both an emission rate that may be met through tradable ERCs, and a requirement to retire tradable allowances qualify as a "standard for emissions." The term "standard" is not defined, but its everyday meaning is a rule or requirement,[15] which, under either a *Chevron* step 1 or step 2 analysis, would include an emission rate that may be met through tradable ERCs and a requirement to retire tradable allowances.

Treating a tradable emission rate or mass limit requirement as a "standard of performance" is consistent with past EPA practice. In the Clean Air Mercury Rule, promulgated in 2005, the EPA established tradable mass limits as the emission guidelines for certain air pollutants from fossil fuel-fired EGUs, and explained that a tradable mass limit qualifies as a "standard for emissions."[16] In addition, in the 1995 Municipal Solid Waste (MSW) Combustor rule the EPA authorized emission trading by sources.[17]

It should be noted that CAA section 302(l) includes another definition of "standard of performance," which is "a requirement of continuous emission reduction, including any requirement

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[15] E.g., "Something that is set up and established by authority as a rule for the measure of quantity, weight, value, or quality." Webster's Third New International Dictionary 2223 (1993).
[16] 70 FR 28606, 28616-17 (May 18, 2005).
[17] 60 FR 65387, 6540/2 (Dec. 19, 1995).

relating to the operation or maintenance of a source to assure continuous emission reduction." As described above, section 111(d) contains its own, more specific definition of "standard of performance," which a tradable emission rate or mass limit satisfies. Whether or not section 302(l) applies in light of section 111(d)'s more specific definition, a tradable emission rate or mass limit also meets section 302(l)'s requirements. A tradable emission rate applies continuously in that the source is under a continuous obligation to meet its emission rate, and that is so regardless of the averaging time, e.g., a rate that must be met on an annual basis. Similarly, an allowance requirement applies continuously in that the source is continuously under an obligation to assure that at the appropriate time, it will have enough allowances to cover its emissions. In this respect, a tradable emission rate or allowance requirement is similar to a non-tradable emission rate that must be met over a specified period, such as one year. In all of these cases, a source is continuously subject to its requirement although it may be able to emit at different levels at different points in time. It should also be noted that a tradable emission rate or allowance program is appropriate for CO_2 emissions, the air pollutant covered by this rule, because CO_2 emissions do not cause short-term health or welfare dangers; rather, their effects occur over a longer term.

(2) In our final rule, we are prescribing certain specific

requirements for trading systems for ERCs in a rate-based approach. These specific requirements are in addition to the generic requirements for any state plan (see section VIII.D.2.d below for the legal basis for the generic components for state plans) and are intended to ensure the integrity of the ERC trading system. The integrity of the trading system is key to ensuring that a state plan provides for implementation and enforcement of the standards of performance.

Here, we explain our interpretation of the phrase "provides for implementation and enforcement of [the] standards of performance" in the context of the integrity of a trading system for ERCs under a rate-based approach. As described previously, the EPA has legal concerns regarding whether requirements under a CAA section 111(d) state plan can be imposed on entities other than affected EGUs. It is important to note that the use of ERCs does not run afoul of these legal concerns, as neither the requirements of section 111(d) nor of the federally enforceable state plan extend to non-EGU generators or third-party verifiers of such compliance units. In the Legal Memorandum we also discuss specific legal issues regarding EM&V criteria, EM&V plans, and Projection guidance.

(3) In our final rule, we are prescribing certain specific requirements for trading systems for allowances in a mass-based approach. These specific requirements are in addition to the generic requirements for any state plan (see section VIII.D.2.d

below for the legal basis for the generic requirements for state plans) and are intended to ensure the integrity of the allowance trading system. The integrity of the trading system is key to ensuring that a state plan provides for implementation and enforcement of the standards of performance.

Our interpretation of the phrase "provides for implementation and enforcement of [the] standards of performance" in the context of the integrity of a trading system for allowances under a mass-based approach is further explained in the Legal Memorandum.

3. "State measures" state plan type

The second type of state plan is what we refer to as a "state measures" plan. As previously discussed, the EPA believes states will be able to submit state plans under the emission standards plan type, and its respective approaches, and achieve the CO_2 emission performance rates or rate-based or mass-based state CO_2 goals by imposing federally enforceable requirements on affected EGUs. Upon further consideration of the requirements of CAA section 111(d), and in consideration of the comments we received on the proposed portfolio approach and the variation of the state commitments approach, the EPA is finalizing the state measures plan type in addition to the emission standards plan type. The EPA believes the state measures plan type will provide states with additional flexibility to accommodate existing or planned programs that involve measures implemented by the state, or by entities other than affected EGUs, that result in avoided generation and CO_2 emission reductions at affected EGUs. This includes market-based emission budget trading programs that apply to affected EGUs, such as the programs implemented by California and the RGGI participating states in the Northeast and Mid-Atlantic, as well as RE and demand-side EE requirements and programs, such as renewable portfolio standards (RPS), energy efficiency resource standards (EERS), and utility- and state-administered incentive programs for the deployment of RE and demand-side EE technologies and practices. The EPA believes this second state plan type will afford states with appropriate flexibility while meeting the statutory requirements of CAA section 111(d).

Measures implemented under the state measures plan type could include RE and demand-side EE requirements and deployment programs. This type of plan could align with existing state resource planning in the electricity sector, including RE and demand-side EE investments by state-regulated electric utilities. The state measures plan type also can accommodate emission budget trading programs that address a broader set of emission sources than just affected EGUs subject to CAA section 111(d), such as the programs currently implemented by California and the RGGI participating states.

This plan type would allow the state to implement a suite of state measures that are adopted, implemented, and enforceable only under state law, and rely upon such measures[18] in achieving the required level of CO_2 emission performance from affected EGUs. The state measures under this plan type could be measures involving entities other than affected EGUs, or a combination of such measures with emission standards for affected EGUs, so long as the state demonstrates that such measures will result in achievement of the CO_2 emission performance rates or applicable state CO_2 emission goal. The EPA notes that under this plan type, a state could also choose to include any emission standards for affected EGUs as federally enforceable requirements in the state plan to be implemented alongside or in conjunction with state measures the state would implement and enforce.

For a state measures plan to be approvable, it must include a demonstration of how the measures, whether state measures or state measures in conjunction with any federally enforceable emission standards, will achieve the CO_2 emission performance rates or state CO_2 emission goal for affected EGUs. However, because the state measures would not be federally enforceable emission standards, the plan must also include a "backstop" of federally enforceable emission standards, in order for the state measures plan type to satisfy the requirement of CAA section 111(d) that a state submit standards of performance for affected

[18] "State measures" refer to measures that the state adopts and implements as a matter of state law. Such measures are enforceable only per applicable state law, and are not included in the federally enforceable state plan.

EGUs. This backstop would impose federally enforceable emission standards on the state's affected EGUs in the case that the state measures fail to achieve the required CO_2 emission performance rates or CO_2 emission goal. The backstop, discussed further below, would assure that the CO_2 emission performance rates or state CO_2 emission goals are fully achieved by affected EGUs in the form of federally enforceable emission standards.

a. Requirements for state measures under a state measures plan. Under the state measures plan type, state measures must be satisfactorily described in the supporting material for a state plan submittal. The supporting material would need to demonstrate that the state measures meet the same integrity elements that would apply to federally enforceable emission standards. Specifically, the state plan submittal must demonstrate that the state measures are quantifiable, verifiable, enforceable, non-duplicative and permanent. These requirements are described in more detail at section VIII.D.2.

The EPA would assess the overall approvability of a plan using a state measures plan type based, in part, on the state's satisfactory demonstration that the state measures, in conjunction with any federally enforceable emission standards on the affected EGUs that might be included in the plan, would result in the state plan's achievement of either the CO_2 emission performance rates or the CO_2 emission goal for the state's affected EGUs. This includes a demonstration of adequate legal authority and funding to implement the state plan and any associated measures. The EPA's determination that such a plan is satisfactory would be based in part on whether the state measures are adequately described in the supporting documentation and the plan submittal demonstrates that the state measures are quantifiable, verifiable, enforceable, non-duplicative and permanent as described above. This is necessary for the EPA to ensure that the results achieved through the plan are quantifiable and verifiable, and to assess whether the state measures are anticipated to achieve the CO_2 emission performance rates or state CO_2 emission goal for affected EGUs.

The EPA's evaluation of the approvability of a state measures plan would also include assessing whether the backstop comprised of federally enforceable emission standards for the state's affected EGUs, in the case that the state measures fail to achieve the required CO_2 emission performance rates or CO_2 emission goal, would assure that the CO_2 emission performance rates or state CO_2 emission goals are fully achieved by affected EGUs. The trigger for the backstop must also satisfactorily provide for the implementation of the backstop emission standards.

b. Considerations for the state measures plan type backstop. As further discussed in section VIII.C.4.c, the EPA believes a backstop, composed of federally enforceable emission standards for the affected EGUs that are sufficient to achieve the state

CO_2 emission goal or meet the CO_2 emission performance rates in the event that state measures do not result in the anticipated CO_2 emission performance, is necessary for the state measures plan type to meet the requirements of CAA section 111(d). The state plan must specify the backstop that would apply federally enforceable emission standards to the affected EGUs if the state measures plan does not achieve the anticipated level of CO_2 emission performance by affected EGUs. The state plan must include promulgated regulations (or other requirements) that fully specify these emission standard requirements.

These federally enforceable emission standards must be designed such that compliance by affected EGUs with the emission standards would achieve the state's rate-based or mass-based interim and final goals for affected EGUs, or the CO_2 emission performance rates. The emission standards must specify CO_2 emission performance levels (in rate or mass) that would apply for the interim plan performance period (including specifying levels for each of the interim step 1 through step 3 periods) and the final two-year plan performance periods.[19] The federally enforceable backstop emission standards for affected EGUs could be designed by the state to take the form of rate-based emission standards or mass-based emission standards. Alternatively, the

[19] This includes the level of emission performance during the interim plan periods 2022-2024, 2025-2027 and 2028-2029, as well as the performance level that would be achieved during every subsequent 2-year final plan performance period (2030-2031, and subsequent two-year periods).

backstop emission standards could be based on the federal plan, using the federal plan regulations as a model rule.

The state measures plan must specify the trigger and conditions under which the backstop federally enforceable emission standards would apply. The trigger and attendant conditions for deployment of the backstop would address the CAA section 111(d) requirement that states submit a program for the implementation of standards of performance. The state measures plan must specify the level of emission performance that will be achieved by affected EGUs as a result of implementation of the state measures plan during the interim and final plan performance periods. This includes the level of emission performance during the interim plan periods 2022-2024, 2025-2027 and 2028-2029, as well as the performance level that would be achieved during every subsequent two-year final plan performance period (2030-2031, and subsequent two-year periods). If actual CO_2 emission performance by affected EGUs exceeds the specified level of emission performance by 10 percent or more during a specified interim or final plan performance period, the state measures plan must require that the backstop federally enforceable emission standards would take effect and be applied to affected EGUs. In the event of such an exceedance, the state measures plan must provide that such emission standards would be effective within 18 months of the deadline for the state's submission of its periodic report to the EPA on state plan implementation and performance, as described in section VIII.D.2.c.[20] While the state is taking any necessary administrative and technical actions to implement the backstop emission standards regulations that were promulgated as part of the state plan, state measures must remain in effect and continue to be implemented by the state until such time as the backstop emission standards are effective.

The backstop emission standards must make up for any shortfall in CO_2 emission performance during a prior plan performance period that led to triggering of the backstopThe state may address the requirement to make up for any shortfall in CO_2 emission performance by submitting as part of the final plan backstop emission standards that assure affected EGUs would achieve the state's rate-based or mass-based interim and final CO_2 goals for affected EGUs, or the CO_2 emission performance rates, and then later submit appropriate revisions to the backstop emission standards adjusting for the shortfall through the state plan revision process. The state may also effectuate this by submitting, along with the backstop emission standards, provisions to adjust the emission standards to account for any prior emission performance shortfall, such that no modification of the emission standards is necessary in order to address the

[20] States may choose to establish an effective date for backstop emission standards that is sooner than 18 months.

emission performance shortfall.

For example, assume a plan identified a mass-based CO_2 standard for affected EGUs of 100 million tons during the interim step 1 performance period (2022-2024), 90 million tons during the interim step 2 performance period (2025-2027), and 80 million tons during the interim step 3 performance period (2028-2029. Over the entire interim plan performance period (2022-2029), the interim mass-based CO_2 goal is cumulative emissions of 270 million tons. Assume that CO_2 emissions from affected EGUs in the interim step 1 period were actually 115 million tons, triggering implementation of the backstop. In this instance, the mass-based standard for affected EGUs implemented as part of the backstop during subsequent plan performance periods would need to ensure that cumulative CO_2 emissions during the 2022-2029 interim period do not exceed 270 million tons. This could be achieved, for example, by implementing a mass standard of 75 million tons during the interim step 2 performance period (rather than the 90 million tons originally specified in the plan), or some other combination during the remaining interim step 2 and 3 performance periods.[21] The emission standards included in the plan must specify calculations for how such adjustments will be made.

[21] In this example, states could elect to implement different combinations of mass-based standards during the remaining interim step 2 and 3 plan performance periods, provided that cumulative CO_2 emissions during the full interim plan performance period (2022-2029) do not exceed 270 million tons.

A similar approach could be applied for a rate-based plan. For example, assume the identified emission performance level during the interim step 1 performance period is 1,000 lb CO_2/MWh and the emission performance level during the interim step 2 performance period is 900 lb CO_2/MWh. Further assume that affected EGUs actually emit at a rate of 1,150 lb CO_2 during the interim step 1 plan performance period. The backstop could apply an emission standard of 750 lb CO_2/MWh during the subsequent interim step 2 plan performance period (rather than the 900 lb CO_2/MWh specified in the emission standard) to make up the emission performance shortfall that led to triggering of the backstop.

c. <u>Addressing emission budget trading programs under the state measures plan type</u>. As described in section VIII.C.3.b(2)(a) above, under the emission standards plan type, a mass-based emission budget trading program must be designed such that compliance by affected EGUs would achieve the state mass-based CO_2 goal. However, emission budget trading programs, including those currently implemented by California and the RGGI participating states, include a number of different design elements. If a state chose, it could apply such mass-based emission standards, in the form of an emission budget trading program that differs in design from that outlined in section VIII.C.3.b(2)(a) above. However, these types of emission budget trading programs must be submitted as a state measure, rather than incorporated as federally enforceable emission standards, as described below.

Such programs could include a number of different design elements. This includes broader program scope, where a program includes other emission sources beyond affected EGUs subject to CAA section 111(d), such as industrial sources. Programs might also include design elements that make allowances available in addition to the established emission budget. This includes project-based offset allowances or credits from GHG emission reduction projects outside the covered sector and cost containment reserve provisions that make additional allowances available at specified allowance prices.[22] In the case where an emission budget trading program contains such elements, compliance by affected EGUs with the mass-based emission standards would not necessarily ensure that CO_2 emissions from affected EGUs do not exceed the state's mass-based CO_2 goal.

The EPA has determined that such emission budget trading programs, which may include broader scope of covered emission sources and the types of provisions described above that functionally expand an established emission budget, may be implemented as part of a state measures plan. A description of

[22] For example, both the California and RGGI programs allow for the use of allowances awarded to GHG offset projects to be used to meet a specified portion of an affected emission source's compliance obligation. The RGGI program contains a cost containment allowance reserve that makes available additional allowances up to a certain amount, at specified allowance price triggers.

the state measures plan type and related requirements is provided in section VIII.C.4.

Under this type of approach, the state would be required to include a demonstration,[23] in its state plan submittal, of how its plan would achieve the state mass-based CO_2 goal. This demonstration would include a projection of the total CO_2 emissions from the fleet of affected EGUs that would occur as a result of compliance with the emission standards in the plan. Section VIII.D.2 discusses how such demonstrations could address design elements of emission budget trading programs with broader scope and additional compliance flexibility mechanisms, such as those included in the California and RGGI programs. Once the plan is implemented, if the mass-based CO_2 goal is not achieved during a plan performance period, the backstop federally enforceable emission standards included in the state plan that apply to affected EGUs would be implemented, as described in section VIII.C.4.b.[24]

d. Legal basis for state measures plan type. The state measures

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[23] A demonstration of how a plan will achieve a state's rate-based or mass-based CO_2 goal is one of the required plan components, as described in section VIII.D.2.

[24] Achievement of the state mass-based CO_2 goal would be determined based solely on stack CO_2 emissions from affected EGUs. Where a state program includes the ability of an affected emission source to use GHG offsets to meet a portion of its allowance compliance obligation, no "credit" is applied to reported CO_2 emissions by the affected EGU. The use of offset allowances or credits in such programs merely allows an affected EGU to emit a ton of CO_2 in the amount of submitted offset allowances or credits. In all cases, there is no adjustment applied to reported stack emissions of CO_2 from an affected EGU when determining compliance with its emission limit.

plan type is consistent with CAA section 111(d). Section 111(d)(1) requires a state to submit a plan that "(A) establishes standards of performance for any existing source for [certain] air pollutant[s] ... and (B) provides for the implementation and enforcement of such standards of performance." Section 111(d)(2)(A) indicates that the EPA must approve the state plan if it is "satisfactory."

Under the state measures plan, a state must submit a state plan that includes standards of performance for CO_2 emissions from affected EGUs in the form of a federally enforceable backstop. Section 111(d) unambiguously allows a state to submit a plan that establishes standards of performance for certain sources, but does not mandate when such standards of performance must be in effect or implemented in order to meet applicable compliance deadlines. The EPA believes because the statute does not provide such a mandate, the EPA therefore has the discretion under section 111(d) to determine the effective date of standards of performance submitted under state plans to meet the requirements of this rule. Where the statute is silent, the EPA has authority to provide a reasonable interpretation, under the U.S. Supreme Court's decision in *Chevron U.S.A. Inc. v. NRDC,* 467 U.S. 837, 842-844 (1984). The EPA's interpretation is that for states that submit state plans establishing standards of performance under section 111(d), the effective date of such standards of performance may be later in time, perhaps indefinitely, for a number of reasons and under certain conditions. The Legal Memorandum discusses in more detail why the EPA believes it is reasonable to defer the effective date for standards of performance for affected EGUs as long as affected EGU CO_2 emissions are projected to achieve, and do achieve, the requisite state goal.

Section 111(d)(2)(B) also requires a state to submit a program that provides for the implementation and enforcement of the applicable standards of performance. Under the state measures approach, this requirement regarding implementation is satisfied by the submission of an approvable trigger mechanism for the backstop and appropriate monitoring, reporting and recordkeeping requirements. The trigger mechanism provides for the "implementation" of the backstop, i.e. the standards of performance, by putting the backstop into effect once the associated trigger is deployed. In other words, when the CO_2 performance level under a state plan exceeds the trigger as described in section VIII.C.4.b, the emission standards that were submitted as the federally enforceable backstop and any attendant requirements must be implemented and in effect. The statutory requirement under CAA section 111(d)(2) regarding enforcement is also satisfied under the state measures plan by the state submitting standards of performance, in the form of the backstop, for inclusion as part of the federally enforceable state plan.

The state measures plan is a variation of the proposed portfolio approach in that both plan types allow the state to rely upon measures that impose requirements on sources other than affected EGUs in meeting the CO_2 emission performance rates or requisite state CO_2 emission performance goal. The state measures plan type differs from the proposed portfolio approach, however, in that the measures involving entities other than affected EGUs are not included as part of the federally enforceable 111(d) state plan, but the state may rely upon such measures that have the effect of reducing CO_2 emissions from affected EGUs as a matter of state law. The EPA took comment on the proposed portfolio approach and the utilization of measures on entities other than affected EGUs in meeting the requirements of the emission guidelines and CAA section 111(d), and is finalizing the state measures plan type upon careful consideration of statutory requirements and comments received.

On May 20, 2015, the Ninth Circuit Court of Appeals issued a decision in *Committee for a Better Arvin et al. v. US EPA et al.*, Nos. 11-73924 and 12-71332, that, at first glance, might be thought to conflict with the state measures approach. The court held that the EPA violated the Clean Air Act by approving a California state implementation plan (SIP) which relied on emission reductions from state-only mobile source standards ("waiver measures") without including those standards in the SIP. The court first looked at the plain language of section 110(a)(2)(A) of the Act, which states that SIPs "shall include" the emission limitations and other control measures on which a state relies to comply with the Act. The court then stated that the EPA's action was also inconsistent with the structure of the Act. The EPA has the primary responsibility to protect the nation's air quality, but in the court's view, the EPA itself would be unable to enforce the state-only standards. In addition, the court stated that the EPA's action was inconsistent with citizens' right to enforce SIP provisions under section 304.

The Ninth Circuit's textual analysis does not apply here, as the language of section 110(a)(2)(A) does not control for 111(d) state plans. Section 111(d)(1) requires state plans to "establish standards of performance" and to "provide for implementation and enforcement" of the standards of performance, but, unlike section 110(a)(2)(A), does not specifically say that every emission reduction measure must be "included" in the state plan and be made federally enforceable. We interpret the state measures approach to satisfy these requirements by establishing a backstop that is the standard of performance and providing for its implementation and enforcement through the federal enforceability of the trigger and backstop.

The Ninth Circuit's structural analysis also does not apply. The availability of the trigger and backstop gives the EPA and citizens a federally enforceable route to ensure that all necessary emission reductions take place in order to achieve the standards of performance. This is markedly different than the state-only standards, where according to the Ninth Circuit, the EPA and citizens had no route to ensure that all necessary emission reductions took place in order to attain the NAAQS. In addition, case law suggests that federal enforceability for every requirement may not be necessary when there are sufficient federally enforceable requirements to satisfy the statute, see National Mining Ass'n v. United States EPA, 59 F.3d 1351 (D.C. Cir. 1995); in this case federal enforceability for the state-only measures is not necessary to meet the statutory requirements of section 111(d)(1) as the federally enforceable trigger and backstop are sufficient.

e. Legal concerns with proposed portfolio approach. The EPA is not finalizing the portfolio approach that was included in the proposed rulemaking, 79 FR 34830, 34902 (June 18, 2014). In the proposal, the EPA noted that the portfolio approach raised legal questions. 79 FR 34830, 34902-03. After reviewing comments, the EPA agrees with commenters that legal questions remain as to whether measures that impose federally enforceable requirements on entities other than affected EGUs either constitute "standards of performance" or "provide[] for the implementation and enforcement of . . . standards of performance" under CAA section 111(d)(1). In addition, shortly after publication of the proposed rulemaking, the U.S. Supreme Court issued the *UARG* decision, which cautions against new extensions of CAA jurisdiction to large segments of the economy, and raises additional questions as to whether entities other than affected EGUs may be included in section 111(d) plans and thereby subject to CAA enforcement authorities. *Utility Air Regulatory Group v. EPA*, 134 S. Ct. 2427 (2014) ("UARG v. EPA").

The state measures plan type the EPA is finalizing is a logical outgrowth of the comments received on the proposed portfolio approach. As previously explained, legal questions remain as to whether federally enforceable state plans under section 111(d) can include measures that impose requirements on sources other than affected EGUs. However, a number of commenters and stakeholders expressed robust support for the ability to rely on measures and programs that do not impose requirements on affected EGUs themselves. The EPA is reasonably interpreting 111(d) as authorizing the state measures plan type, and believes this plan type is also responsive to, and accommodating of, states and stakeholders who have expressed the importance of being able to rely upon various measures that have the effect of resulting in CO_2 reductions from affected EGUs.

4. Summary of comments on state plan approaches

The EPA received a wide range of comments on the basic plan approaches in the proposal. Numerous commenters supported providing states with the option of implementing a rate-based or mass-based approach. Some commenters expressed concern that a rate-based approach would not reduce overall emissions, and could actually lead to increased emissions. The EPA does not agree with this latter comment, because both approaches would result in adequate and appropriate constraints on CO_2 emissions. As documented in the RIA, a rate-based approach would result in a substantial reduction in CO_2 emissions relative to emissions under a business-as-usual case.

Numerous commenters supported allowing states to implement a rate-based emission standard approach applied to affected EGUs. There was also broad support in comments for allowing states to pursue a mass-based approach in the form of mass emission standards on affected EGUs. The EPA is finalizing both approaches, as described below.

The EPA received a mix of comments for and against the proposed portfolio approach, in which state requirements and other measures that apply to non-EGU entities would be part of a state's federally enforceable state plan. Multiple commenters supported the portfolio approach because it would align with existing state and utility planning processes in the electric power sector, and would maximize state discretion in developing plans. Commenters mentioned the range of state requirements and utility programs overseen by states that could be used under a portfolio approach and result in achieving the CO_2 emission goal for affected EGUs, including state RPS, EERS and utility-administered EE programs. Commenters noted that the portfolio approach would provide states maximum flexibility to take local circumstances, economics and state policy into account when developing their plans.

By contrast, multiple commenters opposed the portfolio approach. Some commenters questioned how a portfolio approach would work, and whether the EPA had provided sufficient detail explaining how such a plan approach could be implemented by a state. In particular, multiple commenters questioned how different state programs, such as utility-administered EE programs, could be made federally enforceable in practice under CAA section 111(d).[25] Multiple commenters expressed concern about making state requirements and utility programs for RE and demand-side EE enforceable under the CAA. Some of these commenters supported the state commitments plan approach that the EPA took comment on in the proposal, which was a variant of the portfolio approach. Under the state commitment variant, measures that applied to entities other than affected EGUs would not be federally enforceable under the CAA, but state commitments to implement those measures would be federally enforceable elements of a state plan under the CAA.

After considering these comments, the EPA is not finalizing the portfolio approach. However, the EPA is finalizing the state measures plan type, as described below, that would accommodate state choices and allow states to rely upon a variety of measures, as was envisioned under the portfolio approach, in a way that meets the statutory requirements of CAA section 111(d).

[25] Legal concerns with the proposed portfolio approach are explored in section VIII.C.4.d.

5. Multi-state plans

The EPA views the ability of a state to implement an individual plan or a multi-state plan as a significant flexibility that allows a state to tailor implementation of its plan to state policy objectives and circumstances. The EPA sees particular value in multi-state plans, which allow states to implement a plan in a coordinated fashion with other states. Such approaches can lead to more efficient implementation, lower compliance costs for affected EGUs and lower impacts on electricity ratepayers. Coordinated approaches also will help states identify and address any potential electric reliability impacts when developing plans.

The EPA received broad support in comments for allowing states to implement multi-state plan approaches, and has made multiple changes in the final rule to address many suggestions outlining different approaches states may want to take. These changes are intended to provide streamlined approaches for multi-state coordination while maintaining transparency and assuring that the CO_2 emission performance rates or state CO_2 emission goals are achieved.

The EPA is finalizing two approaches that allow states to coordinate implementation in order to meet the emission guidelines.[26]

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[26] The EPA notes that in addition to these approved approaches, other types of multi-state approaches may be acceptable in an approvable plan, provided the obligations of each state under the

First, states may meet the requirements of the emission guidelines and CAA section 111(d) by submitting multi-state plans that address the affected EGUs in a group of states. The EPA is finalizing the proposed approach by which multiple states aggregate their rate or mass CO_2 goals and submit a plan that will achieve a joint CO_2 emission goal for the fleet of affected EGUs located within those states.

Second, the EPA is also finalizing another approach, in response to comments received on the proposed rule. This approach enables states to retain their individual state goals for affected EGUs and submit individual plans, but to coordinate plan implementation with other states through the interstate transfer of ERCs or emission allowances. This approach facilitates interstate emission trading without requiring states to submit joint plans.[27]

States have the option to implement this second approach in different ways, as discussed in section VIII.C.5.c. These different implementation options allow states to tailor their implementation of linked emission trading programs, based on state policy preferences, as well as economic and other considerations. These different options provide varying levels of state control over emission trading system partners and require

multi-state plan are clear and the submitted plan(s) meets applicable emission guideline requirements.

[27] States may submit individual plans with such linkages, or if they choose, provide a joint submittal. Forms of joint submittals are described at section VIII.E.

varying levels of coordination in the course of state plan development.

In response to comments, the EPA is also further clarifying how multi-state plans with a joint goal for affected EGUs may be implemented. The EPA is clarifying that states may participate in more than one multi-state plan, if necessary, for example, to address affected EGUs in states that are served by more than one ISO or RTO. The EPA is further clarifying that a subset of affected EGUs in a state may participate in a multi-state plan. These clarifications are discussed in section VIII.C.5.d.

a. Summary of comments on multi-state plans. Multiple commenters supported the EPA's proposed approach that allows states to implement a multi-state plan to meet a joint CO_2 emission goal. However, a number of states commented that states should also be allowed to coordinate without aggregating multiple individual state goals into a single joint goal. Many states questioned the incentives that a state would have to aggregate its goal with other states that have different goals.

The EPA notes that there are multiple incentives for states to collaborate by implementing a multi-state plan to meet an aggregated joint goal, regardless of the specific level of their individual goals, because states share grid regions and impacts from plan implementation will be regional in nature. Further, multiple analyses, including those by ISOs and RTOs, indicate that regional approaches could achieve state goals at lesser cost than individual state plan approaches. However, the EPA also recognizes the value in allowing for collaboration where states retain individual goals. These approaches could provide some of the benefits of a joint goal while reducing the negotiations among states necessary to develop a multi-state plan with a joint goal. As a result, the EPA has finalized the additional approaches described above in section VIII.C.5 to provide for coordination while maintaining individual goals. These approaches would allow for interstate transfer of ERCs or emission allowances while retaining individual state goals.

Many commenters suggested that states should be encouraged to join or form regional market-based programs. Many commenters touted the economic efficiency benefits of such approaches, and noted that such programs have features that support electric reliability.

The EPA agrees with these comments, and notes that it encouraged such approaches in the proposal. While the EPA is not requiring states to join and/or form regional market-based programs, we note that such programs can be helpful for many reasons, including features that support reliability. Market-based programs allow greater flexibility for affected EGUs both in the short-term and long-term. Under a market-based program, affected EGUs have the ability to obtain sufficient allowances or credits to cover their emissions in order to comply with their emission limits. Additionally, we continue to encourage states to cooperate regionally. Regional cooperation in planning and reliability assessments is an important tool to meeting system needs in the most cost-effective, efficient, and reliable way.

b. Multistate coordination through a joint emission goal. Multiple states may submit a multi-state plan that achieves an aggregated joint CO_2 emission goal for the affected EGUs in the participating states.[28] The joint emission goal approach is acceptable for both types of state plans, the "emission standards" plan type and the "state measures" plan type. However, the EPA is requiring that a joint goal may apply only to states implementing the same type of plan, either an "emission standards" plan or a "state measures" plan.[29]

[28] As a conceptual and legal matter, the relationship between states coordinating to meet a joint CO_2 emission goal under this rule is similar to the relationship between states coordinating SIP submissions to attain the NAAQS in an interstate nonattainment area. In both cases, the states coordinate their actions in a way that, cumulatively, the measures applicable in each state will lead to achievement of a common interstate goal (with the EPA evaluating the sufficiency and success of the plans on a holistic, interstate basis). Despite the shared goal, in both cases, the mere fact of coordination has no effect on each state's sovereign legal authority. For example, the legally applicable rules in a given state are adopted by that state individually, not by a joint entity or other interstate mechanism. Similarly, the fact that the states coordinate their rules does not grant them the authority to directly enforce each other's rules, or to take direct legal action against a state that is failing to implement its own rules. Although some states may jointly submit their coordinated rules to the EPA as a matter of administrative convenience, the state rules within such a plan are nothing more than reciprocal laws of the sort that states routinely enact in voluntary coordination with each other.

[29] This is necessary because if the joint goal is not achieved during a plan performance period, different remedies would apply under an emission standards plan and a state measures plan. Under an emission standards plan, corrective measures would apply.

Under this approach, a rate-based multi-state plan would include a weighted average rate-based emission goal, derived by calculating a weighted average CO_2 emission rate based on the individual rate-based goals for each of the participating states and 2012 generation from affected EGUs. A mass-based multi-state plan would include an aggregated mass-based CO_2 emission goal for the participating states, in cumulative tons of CO_2, derived by summing the individual mass-based CO_2 emission goals of the participating states.

Such plans could include emission standards in the form of a multi-state rate-based or mass-based emission trading program.[30] Alternatively, states could submit a multi-state plan using a state measures approach.[31] Both approaches could provide for implementation of a multi-state rate-based or mass-based emission trading program.

c. Multi-state coordination among states retaining individual

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Under a state measures plan, the federally enforceable backstop emission standards would be triggered.

[30] A potential example of this approach is the method by which the states participating in RGGI have implemented individual CO_2 Budget Trading Program regulations in a linked manner using a shared emission and allowance tracking system. Each state's regulations implementing RGGI stand alone on a legal basis, but provide for the use of CO_2 allowances issued in other participating states for compliance under the state regulations. These states are not listed by name in state regulations, which instead refer to participating states that have established a corresponding CO_2 Budget Trading Program regulation. More information is available at http://www.rggi.org.

[31] Under this approach, a state measure could include, if a state chose, a multi-state emission trading program that is enforceable at the state level.

state goals. States that do not wish to pursue a joint CO_2 emission goal with other states may pursue a second pathway to multi-state collaboration. States may submit plans that will meet an individual state goal for affected EGUs, but include implementation in coordination with other state plans by providing for the interstate transfer of ERCs or CO_2 allowances, depending on whether the state is implementing a rate-based or mass-based emission trading program. This form of coordinated implementation may occur under both an "emission standards" type of plan and a "state measures" type of plan, where states are implementing rate-based or mass-based emission trading programs.[32]

Under this approach, a state plan could indicate that ERCs or CO_2 allowances issued by other states with an EPA-approved state plan could be used by affected EGUs for compliance with the state's rate-based or mass-based emission standard, respectively. Such plans must indicate how ERCs or emission allowances will be tracked from issuance through use by affected EGUs for compliance,[33] through either a joint tracking system, interoperable tracking systems, or an EPA-administered tracking system.[34]

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[32] ERCs may only be transferred among states implementing rate-based emission limits. Likewise, emission allowances may only be transferred among states implementing mass-based emission limits.
[33] Referred to in different programs as "surrender," "retirement," or "cancellation."
[34] The EPA received a number of comments from states and stakeholders about the value of the EPA's support in developing

The EPA would assess the approvability of each state's plan individually — the use of ERCs or emission allowances issued in another state would not impact the approvability of the components of the individual state plan.[35] However, the EPA would also assess linkages with other state plans, to ensure that the joint tracking system or interoperable tracking systems used to implement rate-based or mass-based emission trading programs across states are properly designed with necessary components, systems, and procedures to maintain the integrity of the linked emission trading programs.

(1) Multi-state coordination: rate-based emission trading programs. Individual rate-based state plans may provide for the interstate transfer of ERCs, which would enable an ERC issued by one state to be used for compliance by an affected EGU with a rate-based emission standard in another state. Such plans would include regulatory provisions in each state's emission standard requirements that indicate that ERCs issued in other partner states may be used by affected EGUs for compliance. Such plans

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and/or administering tracking systems to support state administration of rate-based emission trading programs. The EPA is exploring options for providing such support and is conducting an initial scoping assessment of tracking system support needs and functionality.

[35] Note that for mass-based plans, the approvability requirements for a state plan would differ, depending on the structure of the emission budget trading program included in the state plan. For example, approvability requirements and basic accounting with regard to whether a plan achieves a state's mass CO_2 goal would differ for emission budget trading programs that cover only affected EGUs subject to CAA section 111(d) vs. programs that apply to a broader set of emission sources. These considerations are addressed in subsection VIII.C.5.c.(2)(c).

must indicate how ERCs will be tracked from issuance through use for compliance, through either a joint tracking system, interoperable tracking systems, or an EPA-administered tracking system.[36]

When demonstrating that a state's CO_2 emission goal is achieved as a result of plan implementation, a state with linkages to other states would be required to demonstrate that any ERCs issued by another state that are used by affected EGUs in the state for compliance with its rate-based CO_2 emission standards were issued by states with an EPA-approved state plan.[37]

States could implement these linkages among state plans with rate-based emission trading systems through three different applied implementation approaches: (1) plans that are "ready-for-interstate-trading;" (2) plans that include specified bilateral or multilateral linkages; and (3) plans that provide for joint ERC issuance among states with materially consistent regulations. These approaches are summarized below:

- Ready-for-interstate-trading plans: A state plan recognizes

[36] The emission standards in each individual state plan must include regulatory provisions that address the issuance of ERCs and tracking of ERCs from issuance through use for compliance, as described in subsection VIII.G.3. The description here addresses how those regulatory provisions will be implemented through the use of a joint tracking system, interoperable tracking systems, or an EPA-administered tracking system.

[37] This could be done by reference to data in the tracking system used to implement a state's rate-based emission trading program that identifies the origin of each ERC (e.g., by serial identifier).

ERCs issued by any state with an EPA-approved plan that also uses a specified EPA-approved[38] or EPA-administered tracking system. Plans are approved individually. A state plan need not designate the individual states by name from which it would accept issued ERCs. States can join such a coordinated approach over time, without the need for plan revisions.

- Specified bilateral linkage: States recognize ERCs issued by named partner states. Partner states must demonstrate that they use a shared tracking system, interoperable tracking systems, or an EPA-administered tracking system. Plans are approved individually, including review of the shared tracking system or interoperable tracking systems.
- Joint ERC issuance: States implement materially consistent rate-based emission trading program regulations and share a tracking system. States coordinate their review of submissions for ERC issuance[39] and their issuance of ERCs to the shared tracking system. Issued ERCs are recognized as

[38] The EPA would designate tracking systems that it has determined adequately address the integrity elements necessary for the issuance and tracking of ERCs, as described in subsection VIII.C.5.c.(1). Under this approach, a state could include in its plan such a designated tracking system, which has already been reviewed by the EPA.

[39] This refers to eligibility applications and monitoring and verification reports, which are required submittals for non-affected EGU entities seeking the issuance of ERCs. Where affected EGUs are issued ERCs for emission performance below a specified CO_2 emission rate, these ERCs are issued by the individual state in which they are subject to a rate-based emission standard. Requirements for ERC issuance are discussed in subsection VIII.G.3.

usable for compliance in all states using the shared tracking system. Plans are approved individually, including review of the shared tracking system.

These implementation approaches are designed to streamline the process for linking emission trading programs, avoid or limit the need for plan revisions as new states join a collaborative emission trading approach, and facilitate the development of regional or broader multi-state markets for ERCs.[40]

(2) Multi-state coordination: mass-based emission trading programs. An individual state may provide for the use of CO_2 allowances issued by another state(s) for compliance with the mass-based emission standards in its plan. This type of state plan would include regulatory provisions that enable affected EGUs to use allowances issued in other states for compliance under the state's emission budget trading program. This type of state plan must also indicate how CO_2 allowances will be tracked from issuance through use for compliance, through either a joint tracking system, interoperable tracking systems, or use of an EPA-administered tracking system.[41]

[40] The EPA also notes that individual state plans may utilize RE and demand-side EE (and other eligible measures), that occur in other states, as described in section VIII.G.1 addressing interstate effects. Under an individual state plan, ERCs could be issued for RE and demand-side EE measures that occur in other states, provided the EE/RE provider submits the measures to the state and the measures meet requirements in the state's rate-based emission trading program requirements. The multi-state approaches described above provide additional flexibility for states to informally and formally coordinate their implementation of rate-based plans across states while retaining individual rate-based state goals.

[41] The emission standards in each individual state plan must

Two different implementation approaches could be used to create such links. A state could submit a "ready-for-interstate-trading" plan using an EPA-approved tracking system, but the plan would not identify links with other states. A state could also submit a plan with specified bilateral or multilateral links that explicitly identify partner states.

Interstate allowance linkages would not affect the approvability of each state's individual plan. However, different considerations apply for the approvability of an individual plan with such links, based on whether the emission budget trading program in the plan applies only to affected EGUs or includes other emission sources. These considerations are discussed in section VIII.B.5.c.(2)(a) below.

Under the first "ready-for-interstate-trading" implementation approach, a state would indicate in its state plan that its emission budget trading program will be administered using an EPA-approved (or EPA-administered) emission and allowance tracking system.[42] State plans using a specified EPA-

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include regulatory provisions that address the issuance of CO_2 allowances and tracking of CO_2 allowances from issuance through use for compliance, as described in subsection VIII.C.3.b.(2)(c). The description here addresses how those regulatory provisions will be implemented through the use of a joint tracking system, interoperable tracking systems, or an EPA-administered tracking system.

[42] The EPA would designate tracking systems that it has determined adequately address the integrity elements necessary for the issuance and tracking of emission allowances, as described in subsection VIII.C.5.c.(2). Under this approach, a state could include in its plan such a designated tracking system, which has already been reviewed by the EPA.

approved tracking system would be deemed by the EPA as ready for interstate linkage upon approval of the state plan. No additional EPA approval would be necessary for states to link their emission budget trading programs, and affected EGUs in those states could engage in interstate trading subsequent to EPA plan approval.

A state would indicate in its plan submittal that its emission budget trading system will use a specified EPA-approved tracking system. The state would also indicate in the regulatory provisions for its emission budget trading program that it would recognize as usable for compliance any emission allowance issued by any other state with an EPA-approved state plan that also uses the specified EPA-approved tracking system.

States could also adopt such a collaborative emission trading approach over time (through appropriate state plan revisions if the plan is not already structured as ready-for-interstate-trading), without requiring all of the existing participating states to revise their EPA-approved plans.

Under the second implementation approach, a state could specify the other states from which it would recognize issued emission allowances as usable for compliance with its emission budget trading program. The state would indicate in the regulatory provisions for its emission budget trading program that emission allowances issued in other identified partner states may be used by affected EGUs for compliance. Such plans must indicate how allowances will be tracked from issuance through use for compliance, through either a joint tracking system, interoperable tracking systems, or EPA-administered tracking system. The EPA would assess the design and functionality of this tracking system(s) when reviewing individual submitted state plans.

Under this approach, states could also join such a collaborative emission trading approach over time. However, all participating states would need to revise their EPA-approved plans. If the expanded linkage is among previously approved plans with mass-based emission standards, approval of the plan revision would be limited to assessing the functionality of the shared tracking system or interoperable tracking systems in order to maintain the integrity of the linked programs.[43]

(a) Considerations for linked emission budget trading programs. For individually submitted plans, interstate emission allowance linkages would not affect the approvability of each state's plan. However, approvability of an individual linked plan would differ based on the structure of the emission budget trading program included in the plan. These differences for plan approvability address distinctions among programs that include only affected

[43] Depending on the specific regulatory provisions in the emission standards in their approved state plans, participating states may also need to revise their implementing regulations (and by extension their state plans) to accept CO_2 emission allowances issued by new partner states as usable for compliance with their mass-based emission standards.

EGUs and programs that cover a broader set of emission sources. Differences in approval criteria are necessary to ensure that each individual state plan demonstrates it will achieve a state's mass-based CO_2 emission goal for affected EGUs. The accounting applied to individual plans to assess whether a state achieves its mass-based CO_2 goal will also differ, based on whether an emission budget trading program includes only affected EGUs or a broader set of emission sources. These considerations are addressed below, for both types of emission budget trading programs.

(i) Links among emission budget trading programs that only include affected EGUs. Where the emission budget trading programs in each plan apply only to affected EGUs subject to CAA section 111(d), and include compliance timeframes that align with the interim and final plan performance periods, both plans would functionally be meeting an aggregated multi-state mass-based goal, but without formally aggregating the goal. CO_2 emissions from affected EGUs in both states could not exceed the total combined CO_2 emission budgets under the emission standards in the two states. A net "import" of CO_2 allowances from one state would mean that allowable CO_2 emissions in the other net "exporting" state are less than that state's established emission budget. On a multi-state basis, CO_2 emissions from affected EGUs could not exceed the sum of the states' emission budgets.

Under this approach, if the emission budget for the mass-based emission standard in each plan is equal to or lower than the state's mass-based CO_2 goal, compliance by affected EGUs with the mass emission standard in a state[44] would ensure that cumulatively the mass CO_2 goals of the linked states are achieved. As a result, achievement of an individual state's mass CO_2 goal would be assessed by the EPA based on compliance by affected EGUs with the mass-based emission standards in the state plan, rather than reported CO_2 emissions by affected EGUs in the state.[45]

The same accounting approach will apply for such plans in all cases, even if the state is linked to another state emission budget trading program that includes a broader set of emission sources, as described below. In all cases, where a state plan includes an emission budget trading program that applies only to affected EGUs, and includes compliance timeframes that align with plan performance periods, achievement of a state mass CO_2 goal will be assessed by the EPA based on whether affected EGUs comply with the mass-based emission standard, rather than reported CO_2 emissions from affected EGUs.

(ii) Links with emission budget trading programs that include a broader set of emission sources. State plans may include emission

[44] Compliance by an affected EGU with the emission standard is demonstrated based on surrender to the state of a number of CO_2 allowances equal to its reported CO_2 emissions.

[45] This approach is warranted because under such linked programs, CO_2 emissions from affected EGUs in one state that exceed a state's mass CO_2 goal would be accompanied by CO_2 emissions from affected EGUs in another linked state that are below that state's mass CO_2 goal.

budget trading programs that include affected EGUs as well as other non-affected emission sources.[46]

Generally, as described in section VIII.C.3-4 above, such plans must demonstrate that the mass-based CO_2 goal for affected EGUs in a state will be achieved, as a result of implementation of the emission budget trading program.[47] Where such a program is linked with other programs, the state plan must include a demonstration that the mass-based CO_2 goal will be achieved, considering the emission allowance links with other programs. The EPA, in determining the approvability of each state's plan under this approach, would evaluate the linkages between plans. Specifically, the EPA would evaluate whether the linkages would enable the EGUs in each participating state to meet the state's applicable mass-based CO_2 goal.

During plan implementation, the EPA would assess whether the affected EGUs in a state achieved the state's mass-based CO_2 goal as follows. Reported CO_2 emissions from affected EGUs under such plans must be at or below a state's mass-based CO_2 emission goal during an identified plan performance period, with the following

[46] This may apply under both an emission standards plan and a state measures plan.

[47] Under a program that applies to affected EGUs and other emission sources, compliance by affected EGUs with the emission standard – a requirement to surrender emission allowances equal to reported emissions – will not assure that a state's CO_2 mass goal is achieved. As a result, a further demonstration is required in the plan that compliance by affected EGUs with the program will result in CO_2 emissions from affected EGUs that are at or below a state's CO_2 mass goal.

state accounting adjustments for net "import" and net "export" of CO_2 allowances:

- <u>Net "imports" of CO_2 allowances</u>: Reported CO_2 emissions from affected EGUs in a state may exceed the state CO_2 mass goal during an identified plan performance period in the amount of an adjustment for the net "imported" CO_2 allowances during the plan performance period. The adjustment represents the CO_2 emissions (in tons) equal to the number of net "imported" CO_2 allowances.[48] Under this adjustment, such allowances must be issued by a state with an emission budget trading program that only applies to affected EGUs. Net "imports" of allowances are determined through review of tracking system compliance accounts.
- <u>Net "exports" of CO_2 allowances</u>: Reported CO_2 emissions from affected EGUs in a state during an identified plan performance period must be equal to or less than the CO_2 mass goal minus an adjustment for the "exported" CO_2 allowances during the plan performance period. The adjustment represents CO_2 emissions (in tons) equal to the number of net "exported" CO_2 allowances. Net "exports" of allowances are determined through review of tracking system compliance accounts.

Where CO_2 emissions from affected EGUs exceed these levels

[48] Net "imports" and "exports" of CO_2 allowances are defined and explained below.

(based on reported CO_2 emissions with applied plus or minus adjustments for net CO_2 allowance "imports" or "exports") by 10 percent or more, a state would be considered to not have met its CO_2 mass goal during an identified plan performance period. As a result, under a state measures state plan, implementation of the backstop federally enforceable emission standards for affected EGUs in the state plan would be triggered.

A net transfer of CO_2 allowances during a plan performance period represents the net number of CO_2 allowances (issued by a respective state) that are transferred from the compliance accounts of affected EGUs in that state to the compliance accounts of affected EGUs in another state.[49] This net transfer is determined based on compliance account holdings at the end of the plan performance period.[50] For example, assume two states,

[49] A net transfer metric is applied as of the end of the plan performance period. This net accounting as of a specified date is necessary because multiple individual allowance transfers may occur among accounts during a plan performance period, representing normal trading activity. In addition, net transfers are based on compliance account holdings, because these represent the CO_2 allowances directly available at that point in time for use by an affected EGU for complying with its emission limit. Emission budget trading programs typically allow non-affected entities to hold allowances in general accounts. These parties are free to hold and trade CO_2 allowances, providing market liquidity. General account holdings are not assessed as part of a periodic state net transfer accounting, as these allowances may subsequently be transferred to other accounts in multiple states and do not represent allowances currently held by an affected EGU that can be used for complying with its emission limit.

[50] Compliance account holdings, as used here, refer to the number of CO_2 allowances surrendered for compliance during a plan performance period, as well as any remaining CO_2 allowances held in a compliance account as of the end of a plan performance period.

State A and State B, with emission budgets of 1,000 tons of CO_2. Each state issues 1,000 CO_2 allowances. At the end of a plan performance period, affected EGUs in State A collectively hold 500 CO_2 allowances in their compliance accounts that were issued by State A. Affected EGUs in State B collectively hold in their compliance accounts 500 CO_2 allowances issued by State A and 1,000 CO_2 allowances issued by State B. In this simplified example, a net transfer of 500 CO_2 allowances has occurred between State A and State B. State A has "exported" 500 CO_2 allowances to State B, while State B has "imported" 500 CO_2 allowances from state A.

d. Multi-state plans that address a subset of EGUs in a state. The EPA is clarifying in the final emission guidelines that a state may participate in more than one multi-state plan. Under this approach, the state would identify in its submittal the subset of affected EGUs in the state that are subject to the multi-state plan or plans. This could involve a subset of affected EGUs that are subject to a multi-state plan, with the remainder of affected EGUs subject to a state's individual plan. Alternatively, different affected EGUs in a state may be subject to different multi-state plans. In all cases, the state would need to identify in each specific plan which affected EGUs are subject to such plan, with each affected EGU subject to only one multi-state plan or subject only to the state's individual plan (if relevant).

These scenarios may occur where a state chooses to subject affected EGUs in different ISOs or RTOs to different multi-state plans. This will provide states with flexibility to participate in multi-state plans that address the affected EGUs in a respective grid region, in the case where state borders cross grid regions.

These scenarios may also occur where a state is served by multiple vertically integrated electric utilities with service territories that cross state lines. This will provide states with flexibility to participate in multi-state plans that address the affected EGUs owned and operated by a utility with a multi-state service territory.

e. Legal issues regarding multi-state plans. While nothing in section 111(d)(1) explicitly authorizes states to adopt and submit multi-state plans and for the EPA to approve them as satisfactory, nothing in section 111(d)(1) explicitly prohibits this, either. In addition, nothing in section 111(d)(2)(A)'s standard of "satisfactory" prohibits the EPA from considering multi-state plans as satisfactory. There is thus a gap that the EPA may reasonably fill.

In light of the purpose of these emission guidelines, to reduce emissions of a pollutant that globally mixes in the stratosphere, and the mechanisms to reduce those emissions, which may have beneficial effects across state lines, it is reasonable to allow for multi-state plans. Thus, our gap-filling interpretation of section 111(d) in this context is reasonable.

D. State Plan Components and Approvability Criteria

1. Approvability Criteria

In the "Criteria for Approving State Plans" section of the preamble to the June 2014 proposal (section VIII.C), the EPA proposed the following as necessary components of an approvable state plan:

1. The plan must contain enforceable measures that reduce EGU CO_2 emissions;

2. The enforceable measures must be projected to achieve emission performance equivalent to or better than the applicable CO_2 emission performance rates or state-specific CO_2 goal on a timeline equivalent to that in the emissions guidelines;

3. The EGU CO_2 emission performance must be quantifiable and verifiable;

4. The plan must include a process for state reporting of plan implementation, CO_2 emission performance outcomes, and implementation of corrective measures, if necessary.

After reviewing the comments we received concerning the approvability criteria, the EPA has decided against maintaining the four proposed approvability criteria separately from the list of components required for an approvable plan, which may be confusing and potentially redundant. The EPA has determined that a satisfactory state plan that meets the required plan components discussed below will inevitably meet the proposed approvability criteria. The EPA, therefore, has incorporated the proposed approvability criteria into the section titled "Components of a state plan submittal" (section VIII.D.2 below), which results in no functional change in the approvability criteria or the components of a state plan addressed in the proposal. We do not expect this change to have a substantive effect on state plan development or approval.

Under the proposed "Enforceable Measures" criterion (section VIII.C.1 of the proposal preamble), the EPA specifically requested comment on the appropriateness of applying existing EPA guidance on enforceability to state plans under CAA section 111(d), considering the types of entities that might be included in a state plan.[51]

The EPA also requested comment on whether the agency should provide guidance on enforceability considerations related to requirements in a state plan for entities other than affected EGUs, and if so, what types of entities. Comments received strongly suggested that the EPA provide guidance on enforceability considerations for non-EGU affected entities, particularly for RE and EE. Comments also requested additional guidance specific to this rulemaking, including examples of

[51] The existing guidance documents referenced were: (1) September 23, 1987 memorandum and accompanying implementing guidance, "Review of State Implementation Plans and Revisions for Enforceability and Legal Sufficiency;" (2) August 5, 2004 "Guidance on SIP Credits for Emission Reductions from Electric-Sector Energy Efficiency and Renewable Energy Measures;" and (3) July 2012 "Roadmap for Incorporating Energy Efficiency/Renewable Energy Policies and Programs into State and Tribal Implementation Plans, Appendix F."

enforceable measures for specific activities, such as solar thermal programs, waste heat recovery, net-metering energy savings and state RPSs.

These enforcement considerations arose primarily under the proposed portfolio approach for state plans. In this action, the EPA is finalizing the state measures approach instead of the portfolio approach described in the proposed rule. As explained in section VIII.C, the EPA is not finalizing the portfolio approach, which would have allowed state plan submittals to include federally enforceable measures that apply to entities that are not affected EGUs. However, as explained in depth in section VIII.C, if the state is adopting the state measures approach, the state plan submittal will need to specify, in the supporting materials, the state enforceable measures that the state is relying upon in conjunction with any federally enforceable emission standards for affected EGUs to meet the emission guidelines. As part of the state measures approach, the EPA is finalizing a federally enforceable backstop which requires the affected EGUs to meet emission standards that fully achieve the CO_2 emission performance rates or the state's CO_2 emission goal if the state measures do not meet the intended emission performance levels. Because the EPA is not finalizing the portfolio approach, which would have allowed states to include enforceable measures in a state plan that apply to entities that are not affected EGUs, the agency is not providing additional guidance on federal enforceability of measures that might apply to such entities. As proposed, we are requiring that state plans include a demonstration that plan measures are enforceable, which for emission standard plans is discussed in section VIII.D.2.b.4 below and for state measures plans is discussed in section VIII.D.2.c.6 below.

Commenters also requested that the EPA allow states to rely on provisions with flexible compliance mechanisms in state plans and clarify how to address flexible compliance mechanisms when demonstrating achievement of the state CO_2 emission goal. Additionally, a commenter requested that the enforceability mechanisms that the EPA requires in state plans should support existing programs, as well as new programs in other states, by minimizing program changes required purely to conform with federal requirements, while still providing enough additional program review and accounting to ensure that CO_2 emission reductions are achieved. These and related comments contributed to the EPA's decision to finalize the option for states to submit a state measures plan, which would be comprised, at least in part, of measures implemented by the state that are not included as federally enforceable components of the plan, with a backstop of federally enforceable emission standards for affected EGUs that fully meet the emission guidelines and that would be triggered if the plan failed to achieve the CO_2 emission performance levels specified in the plan on schedule. For more information on the state measures plan approach, see section VIII.C.4 of this preamble above.

2. Components of a state plan submittal

In this action, the EPA is finalizing that a state plan submittal must include the components described below. The state plan submittal must also be consistent with additional specific requirements elsewhere in this final rule and with the EPA implementing regulations at 40 CFR 60.23-60.29, except as otherwise specified by this final rule. These requirements apply to both individual state plan submittals and multi-state plan submittals. When a state plan submittal is approved by the EPA, the EPA will codify the approved CAA section 111(d) state plan in 40 CFR part 62. Section VIII.D.3 discusses the components of the state plan submittal that would be codified as the state CAA section 111(d) plan when the state plan submittal is approved by the EPA.

The EPA is finalizing that states can choose to meet the emission guidelines through one of two types of state plans: an "emission standards approach" plan or a "state measures approach" plan. States may also opt to submit a plan that meets the CO_2 emission performance rates for affected EGUs or achieves a state rate-based or mass-based CO_2 emission goal. The content of the state plan submittal will vary depending on which approach the state decides to adopt. States that choose to participate in multi-state plans must adequately address plan components that apply to all participating states in the multi-state plan. Section VIII.D.2.a addresses the components required for all plan submittals. Section VIII.D.2.b addresses the additional components required for submittals under the emission standards plan approach. Section VIII.D.2.c addresses additional components required for submittals under the state measures plan approach.

a. Components required for all state plan submittals. The EPA is finalizing requirements that a final plan submittal must contain the following components, in addition to those in either section VIII.D.2.b (for the emission standards plan approach) or VIII.D.2.c (for the state measures plan approach) of this section.

(1) Description of the plan approach and geographic scope. The description of the plan approach must indicate whether the state will meet the emission guidelines on an individual state basis or jointly through a multi-state approach, and whether the state is adopting an emission standards approach plan or a state measures approach plan. For multi-state plans this component must identify all participating states and geographic boundaries applicable to each component in the plan submittal.

(2) Identification of interim period emission performance rates or state goal (for 2022-2029), interim step performance rates or interim state goals (2022-2024; 2025-2027; 2028-2029) and final emission performance rates or state goal (2030 and beyond). The state plan submittal must indicate whether the plan is designed

to meet the CO_2 emission performance rates or the state CO_2 emission goal. As noted in the emission guidelines, the EPA is finalizing state goals in the form of a CO_2 emission rate (emission rate-based goal) and in the form of tonnage CO_2 emissions (mass-based goal). The state may adopt either the rate-based or the mass-based state CO_2 emission goal provided in the emission guidelines. If the state chooses the option of developing a plan that achieves the state CO_2 emission goal, the state plan submittal must identify the rate-based or mass-based CO_2 emission goal that must be achieved through the plan (expressed in numeric values, including the units of measurement, such as pounds of CO_2 per net MWh of useful energy output or tons of CO_2). The plan submittal must identify the state CO_2 interim period goal (for 2022-2029), interim steps goals (interim step goal 1 for 2022-2024; interim step goal 2 for 2025-2027; interim step goal 3 for 2028-2029) and final CO_2 emission goal of 2030 and beyond.

For each state, the EPA has finalized an interim goal for the interim period of 2022-2029 and a final goal to be met by 2030. For the interim period, the EPA has also finalized three interim step goals: interim step 1 goal for 2022-2024, interim step 2 goal for 2025-2027 and interim step 3 goal for 2028-2029.[52] States are free to establish different interim step goals

[52] In this action, the EPA is providing interim state goals in the form of a CO_2 emission rate (emission rate-based goal) and in the form of tonnage CO_2 emissions (mass-based goal).

than those the EPA has specified in this final rule. If states choose to determine their own interim step goals, the state must demonstrate that it will still meet the interim goal for 2022-2029 finalized in this action and the plan submittal must include in its supporting documentation a description of the analytic process, tools, methods, and assumptions used to make this demonstration.

The final rule allows states the opportunity to switch from a rate-based CO_2 goal for the interim plan performance period (2022-2029) to a mass-based CO_2 goal for the final plan performance period (2030 and onward). Conversely, a state plan may use a mass-based CO_2 goal for the 2022-2029 interim period, and a rate-based CO_2 goal for the final goal plan performance periods. Some commenters requested that flexibility be provided to allow states to switch from rate-based goals to mass-based goals either as a one-time change between the interim goal to the final goal, or more frequently if necessary year-by-year. The EPA recognizes that it may be necessary to switch between rate-based goals and mass-based goals, and therefore provides the option for states to change approaches between the interim plan performance period and the final plan performance period. To ensure progress toward the goals, maintain consistency with rule provisions, and minimize delays due to plan revisions, the EPA does not grant states the ability to change approaches more often than from the interim period to the final period. For instance, if a state plan indicates that a mass-based CO_2 goal will be used for demonstrating achievement of the interim goal, then that state will be required to demonstrate achievement of the specified mass-based interim steps on a mass basis, and will have the option to change to a rate-based approach for the final plan performance period.

For states participating in a multi-state plan with a joint goal (for interim and final periods), the individual state goals in the emission guidelines would be replaced with an equivalent multi-state goal for each period (interim and final). For a rate-based multi-state plan this would be a weighted average rate-based emission goal, derived by the participating states, by calculating a weighted average CO_2 emission rate based on the individual rate-based goals for each of the participating states and 2012 generation from affected EGUs. For a mass-based multi-state plan, the joint goal would be a sum of the individual mass-based goals of the participating states, in tons of CO_2. The plan submittal must include in its supporting documentation a description of the analytic process, tools, methods, and assumptions used to calculate the joint multi-state goal.

(3) Applicability of state plans to affected EGUs. The state plan submittal must list the individual affected EGUs that meet the applicability criteria of § 60.5805 and provide an inventory of CO_2 emissions from those affected EGUs for the most recent calendar year prior to plan submission for which data are available.

(4) <u>Monitoring, reporting and recordkeeping requirements for affected EGUs</u>. The state plan submittal must specify how each emission standard is quantifiable and verifiable by describing the CO_2 emission monitoring, reporting and recordkeeping requirements for affected EGUs. The applicable monitoring, recordkeeping and reporting requirements for affected EGUs with are outlined in section VIII.F.

In the June 2014 proposal, the EPA proposed that states must include in their state plans a record retention requirement for affected EGUs to maintain records for at least 10 years following the date of each occurrence, measurement, maintenance, corrective action, report or record. Commenters requested clarification of the record retention requirements for states vs. for affected EGUs and also requested that the EPA clarify onsite vs. offsite record maintenance requirements for affected EGUs. Consistent with state recordkeeping requirements, the EPA is finalizing that states must include in their plans a record retention requirement for affected EGUs of not less than 5 years following the date of each compliance period, occurrence, measurement, maintenance, corrective action, report, or record., that affected EGUs must maintain each record onsite for at least 2 years after the date of the occurrence of each record and may maintain records offsite and electronically for the remaining years. Each record must be in a form suitable and readily available for expeditious review. The EPA finds that these final recordkeeping requirements are appropriate and consistent with the requirements for other CAA section 111(d) emission guidelines.

(5) State reporting and recordkeeping requirements. A state plan submittal must contain the process, content and schedule for state reporting to the EPA on plan implementation and progress toward meeting the CO_2 emission performance rates or state CO_2 emission goal.

The EPA is finalizing state reporting requirements based on the type of plan approach the state chooses to adopt and implement. These state reporting requirements are discussed in section VIII.D.2.b (for emission standards approach) and VIII.D.2.c (for state measures approach).

In addition to the state reporting requirements discussed in section VIII.D.2.b (for emission standards approach) and VIII.D.2.c (for state measures approach) and as discussed below, states must include in the supporting material of a final state plan submittal a timeline with all the programmatic milestone steps the state will take between the time of the state plan submittal and 2022 to ensure the plan is effective as of 2022. The EPA is also finalizing a requirement that states must submit a report to the EPA in 2021 that demonstrates that the state has met the programmatic milestone steps that the state indicated it would take from the submittal of the final plan through the end of 2020, and that the state is on track to implement the approved state plan as of January 1, 2022. An approvable final state plan submission must include a requirement for the state to submit this report to the EPA no later than July 1, 2021. If the EPA approves a state plan that includes the required obligation on the state to submit this report, and the state either does not submit the requisite report by July 1, 2021, or the state submits a report demonstrating it has not met the programmatic milestones, the EPA's approval of the state plan will convert to a disapproval. Per the requirements of CAA section 111(d), the EPA will develop and implement a federal plan in the instance of such disapproval. As discussed in section VIII.B, if a state demonstrates, in its July 1, 2021 report, that it has implemented such early action measures, the EPA will consider its report to be presumptively approvable.

The EPA is finalizing a requirement for states to electronically submit state plan submittals, any supporting materials that are part of a state plan submittal, and state reports required by the state plan. The EPA is developing an electronic system to support this requirement that can be accessed at the EPA's Central Data Exchange (CDX) (http://www.epa.gov/cdx/). See Section VIII.E.7 for additional information on electronic submittal requirements.

In the June 2014 proposal, the EPA proposed that states must keep records at minimum for 20 years of all plan components, plan requirements, plan supporting documentation and status of meeting the plan requirements, including records of all data submitted by each affected EGU used to determine compliance with emission standards. The EPA received multiple comments recommending that the EPA reduce recordkeeping requirements due to the burden in expenditure of resources and manpower to maintain records for at least 20 years. Commenters recommended that recordkeeping requirements be reduced to 5 years consistent with emission guidelines for other existing sources.

After considering the comments received, this final rule requires that a state must keep records of all plan components, plan requirements, supporting documentation, and the status of meeting the plan requirements defined in the plan for the interim steps 1, 2 and 3 and the interim plan period from 2022-2029. After 2029, states must keep records of all information relied upon in support of any continued demonstration that the final CO_2 emissions performance rates or goals are being achieved. The EPA agrees with comments that a 20-year record retention requirement could be unduly burdensome, and has reduced the length of the record retention requirement for the final rule. During the interim period, states must keep records for 10 years from the date of conclusion of each compliance period for its EGUs and/or plan performance period. During the final period, states must keep records for 5 years from the date of conclusion of each compliance period for its EGUs and/or plan performance period. All records must be in a form suitable and readily available for expeditious review. States must also keep records of all data submitted by each affected EGU that was used to determine compliance with each affected EGU's emission standard, and such data must meet the requirements of the emission guidelines, except for any information that is submitted to the EPA electronically pursuant to requirements in 40 CFR part 75. If the state is adopting and implementing the state measures approach, the state must also maintain records of all data regarding implementation of each state measure and all data used to demonstrate achievement of CO_2 emission performance rates or CO_2 emission goal and such data must meet the requirements of the emission guidelines. The EPA finds that these final recordkeeping requirements balance the need to maintain records while reducing the strain on state resources.

(6) Certification of hearing on state plan. For the final plan submittal, states must meaningfully engage with all members of the public, including communities and tribes, during the plan development process. The existing implementing regulations regarding public participation requirements are in 40 CFR 60.23(c)-(f). Per the implementing regulations, states must conduct a public hearing on a final state plan before such plan is adopted and submitted. In its plan submittal, a state must provide certification that the state gave reasonable notice and opportunity for public comment on the state plan. The state must demonstrate that the public hearing on the state plan was held only after reasonable notice, which will be considered to include, at least 15 days prior to the date of such hearing,

notice given to the public by prominent advertisement announcing the date(s), time(s) and place(s) of such hearing(s). For each hearing held, a state plan submittal must include in the supporting documentation the list of witnesses and their organizational affiliations, if any, appearing at the hearing, and a brief written summary of each presentation or written submission pursuant to the requirements of the implementing regulations at 40 CFR 60.23. Additionally, the EPA recommends that states work with local municipalities, community-based organizations and the press to advertise their state hearing(s).

As previously discussed in this rule, recent studies also find that certain communities, including low-income communities and some communities of color, are disproportionately affected by certain climate change related impacts. Also as discussed in this rule, effects from this rule can be anticipated to impact communities in various ways. Because certain communities have a potential likelihood to be impacted by state plans, the EPA believes that the existing public participation requirements under 40 CFR 60.23 are effectuated for the purposes of this final rule by states engaging in meaningful, active ways with such communities.

The EPA notes that meaningful public involvement goes beyond the holding of a public hearing. In section VIII.E, the EPA provides states with resources on how to engage with affected communities in a meaningful way. With respect specifically to ensuring meaningful community involvement in their public hearing(s), however, the EPA recommends that states have both a website and toll-free number that all stakeholders, including affected communities, can access to get more information regarding the upcoming hearing(s). In addition, the EPA recommends that states provide all communities with a mechanism on their website and on the toll-free number to get their questions related to upcoming hearings answered. Furthermore, the EPA recommends that states work with their local government partners to help them in reaching out to all stakeholders, including affected communities about the upcoming public hearing(s).

(7) Supporting documentation. The state plan submittal must provide supporting material and technical documentation related to applicable components of the plan submittal.

(a) Legal authority. In its submittal, a state must adequately demonstrate that it has the legal authority (regulations/legislation) and funding to implement and enforce each component of the state plan submittal, including federally enforceable emission standards for affected EGUs and state measures. A state can make such a demonstration by providing supporting material related to the state's legal authority used to implement and enforce each component of the plan, such as copies of statutes, regulations, PUC orders, and any other applicable legal instruments. For states participating in a multi-state plan, the submittal(s) must also include as supporting documentation each state's necessary legal authority to implement the portion of the plan that applies within the particular state, such as copies of state regulations and statutes, including a showing that the states have the necessary authority to enter into a multi-state agreement.

(b) Technical documentation. As applicable, the state submittal must include materials necessary to support the EPA's evaluation of the submittal including analytical materials used in the calculation of interim goal steps, multi-state goal calculation (if joint multi-state demonstration), analytical materials used in projecting CO_2 emission performance that will be achieved through the plan, relevant implementation materials and any additional technical requirements and guidance the state proposes to use to implement elements of the plan.

(c) Programmatic milestones and timeline. As part of the state plan supporting documentation, the state must include in its submittal a timeline with all the programmatic milestone steps the state will take between the time of the state plan submittal and 2022 to ensure the plan is effective as of 2022. The programmatic milestones and timeline should be appropriate to the overall state plan approach included in the state plan submittal.

(d) Reliability. As discussed in section VIII.H.2, each state must demonstrate that it has considered reliability issues while developing its plan.

b. Additional components required for the emission standards approach. The EPA is finalizing requirements that a final plan submittal using the emission standards approach must contain the following components, in addition to the components discussed in section VIII.D.2.a.

(1) Identification of federally enforceable emission standards for affected EGUs. The state plan submittal must include federally enforceable emission standards that apply to affected EGUs. The emission standards must meet the requirement of component 2 of this section, "Demonstrations that each emission standard is quantifiable, non-duplicative, permanent, verifiable, and enforceable." The plan must identify the affected EGUs to which these standards apply. The compliance periods for each emission standard for affected EGUs, on a calendar year basis, must be as follows for the interim period: January 1, 2022 – December 31, 2024; January 1, 2025 – December 31, 2027; and January 1, 2028 – December 31, 2029. Starting on January 1, 2030, the compliance period for each emission standard is every 2 calendar years. States can choose to set shorter schedules of compliance for the emission standards but no longer than the compliance periods the EPA is finalizing in this rulemaking. As discussed in more detail in section VIII.F, the EPA recognizes that the compliance periods provided for in this rulemaking are longer than those historically and typically specified in CAA rulemakings. The EPA determined that the longer compliance

periods provided for in this rulemaking are acceptable in the context of this specific rulemaking because of the unique characteristics of this rulemaking, including that CO_2 is long-lived in the atmosphere, and this rulemaking is focused on performance standards related to those long-term impacts.

For state plans in which affected EGUs may rely upon the use of ERCs for meeting a rate-based federally enforceable emission standard, the emission standards in the state plan must include requirements addressing the issuance, tracking and use for compliance of ERCs consistent with the requirements in the emission guidelines. The state plan must also demonstrate that the appropriate ERC tracking infrastructure that meets the requirements of the emission guidelines will be in place to administer the state plan requirements regarding ERCs and document the functionality of the tracking system. State plan requirements must include provisions to ensure that ERCs are properly tracked from issuance to submission for compliance. The state plan must also demonstrate that the MWh for which ERCs are issued are properly quantified and verified, through state EM&V and other verification plan requirements that meet the requirements in the emission guidelines. Rate-based emission standards must also include monitoring, reporting, and recordkeeping requirements for CO_2 emissions and useful energy output for affected EGUs; and related compliance demonstration requirements and mechanisms. All of these requirements are discussed in more detail in sections VIII.G.3 and 4.

For state plans using a mass-based emission trading program approach, the emission standards in the state plan must include requirements that specify the emission budget and related compliance requirements and mechanisms. These requirements must include: CO_2 emission monitoring, reporting, and recordkeeping requirements for affected EGUs; provisions for state allocation of allowances; provisions for tracking of allowances, from issuance through submission for compliance; and the process for affected EGUs to demonstrate compliance (allowance "true-up" with reported CO_2 emissions.)

(2) Demonstration that each emission standard is quantifiable, non-duplicative, permanent, verifiable and enforceable. The plan submittal must demonstrate that each emission standard is quantifiable, non-duplicative, permanent, verifiable and enforceable with respect to an affected EGU, as outlined below.

An emission standard is quantifiable if it can be reliably measured, using technically sound methods, in a manner that can be replicated.[53]

An emission standard is non-duplicative with respect to an

[53] CO_2 continuous emissions monitoring system (CEMS) is the most technically reliable method for EGUs. CEMS provide a measurement method that is performance based rather than equipment specific which is verified based on NIST traceable standards. CEMS provide a continuous measurement stream that can account for variability in the fuels and the combustion process. Reference methods have been developed to ensure that all CEMS meet the same performance criteria which helps to ensure a level playing field and consistent, accurate data.

affected EGU if it is not already incorporated in another state plan, except in instances where incorporated as part of a multi-state plan. An example of a duplicative emission standard would occur, for example, where a quantified and verified MWh from a wind turbine could be applied in more than one state's CAA section 111(d) plan to adjust the CO_2 emission rate of an affected EGU, except in the case of a multi-state plan where CO_2 emission performance is demonstrated jointly for all affected EGUs subject to the multi-state plan.[54] This does not mean that measures in an emission standard cannot also be used for other purposes. For example, a MWh of electric generation from a wind turbine could be used by an electric distribution utility to comply with state RPS requirements and also be used by an affected EGU comply with emission standard requirements under a state plan. Another example is when actions taken pursuant to CAA section 111(d) requirements can satisfy other CAA program requirements (e.g., Regional Haze requirements, MATS etc.)

An emission standard is permanent if the emission standard

[54] For example, an ERC that is issued by a state under its rate-based emission standards may be used only once by an affected EGU to adjust its reported CO_2 emission rate when demonstrating compliance with the emission standards. However, an ERC issued in one state could be used by an affected EGU to demonstrate compliance with emission standards in another state, where states are collaborating in the implementation of their individual emission trading programs through interstate transfer of ERCs or CO_2 emission allowances, or participating in a multi-state plan with a rate-based or mass-based emission trading program. These coordinated multi-state approaches are addressed in subsection VIII.

must be met for each applicable compliance period.

An emission standard is verifiable if adequate monitoring, recordkeeping and reporting requirements are in place to enable the state and the Administrator to independently evaluate, measure, and verify compliance with it.

An emission standard is enforceable if it: (1) represents a technically accurate limitation or requirement and the time period for the limitation or requirement is specified, (2) compliance requirements are clearly defined, (3) the entities responsible for compliance and liable for violations can be identified, (4) each compliance activity or measure is practically enforceable in accordance with EPA guidance on practical enforceability,[55] and the Administrator and the state maintain the ability to enforce against violations and secure appropriate corrective actions, in the case of the Administrator pursuant to CAA sections 113(a)-(h), and states and other third parties maintain the ability to enforce against violations and secure appropriate corrective actions pursuant to CAA section 304.

In developing its CAA section 111(d) plan, to ensure that the plan submittal is enforceable and in conformance with the CAA, a state should follow the EPA's prior guidance on enforceability.[56] These guidance documents serve as the

[55] See prior footnote.
[56] The EPA guidance on enforceability includes: (1) September 23, 1987, memorandum and accompanying implementing guidance, "Review

foundation for the types of monitoring, reporting, and emission standards that the EPA has found can be, as a practical matter, enforced.

In the proposed regulatory text describing the enforcing measures that states must include in state plans, the EPA inadvertently excluded a required demonstration that states and other third parties can enforce against violations of an emission standard included in a state plan via civil action pursuant to CAA section 304. Commenters noted the EPA's intent to require this demonstration based on statements in both the proposal preamble text and "State Plan Considerations" TSD[57] and based on the requirements of CAA section 304. We are finalizing a requirement for a demonstration that states and other third parties can enforce against violations of an emission standard included in a state plan via civil action as part of the required plan component demonstrating enforceability. We are finalizing this requirement as a logical outgrowth of proposal preamble text, the proposal preamble citation to existing enforceability guidance documents that discuss this requirement, and comments received.

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of State Implementation Plans and Revisions for Enforceability and Legal Sufficiency," (2) August 5, 2004, "Guidance on SIP Credits for Emission Reductions from Electric-Sector Energy Efficiency and Renewable Energy Measures," and (3) July 2012 "Roadmap for Incorporating Energy Efficiency/Renewable Energy Policies and Programs into State and Tribal Implementation Plans, Appendix F."

[57] State Plan Considerations technical support document for the Clean Power Plan Proposed Rule: http://www2.epa.gov/carbon-pollution-standards/clean-power-plan-proposed-rule-state-plan-considerations.

(3) Demonstration that the emission standards contained in the plan achieve the CO_2 emission performance rates or state CO_2 emission goal. A state plan submittal must demonstrate that the federally enforceable emission standards on affected EGUs are sufficient to meet either the CO_2 emission performance rates or the state's CO_2 emission goals in the emission guidelines for the interim and final periods. This includes the interim period of 2022-2029, including interim step 1 2022-2024 period; interim step 2 2025-2027 period and interim step 3 2028-2029 period (or alternative CO_2 emission performance step levels adopted by the state, provided they result in achievement of the CO_2 emission performance rates or state CO_2 emission goal during the 2022-2029 interim period), as well as the final period of 2030 and beyond. The type of demonstration required for emission standards plans will vary depending on how the CO_2 emission performance standards are applied across the fleet of affected EGUs in a state, as described below.

(a) Demonstration for a rate-based emission standards state plan. The type of demonstration for a rate-based emission standards plan depends on the design of the plan submitted to the EPA.

When a state submits an emission standards plan that establishes separate rate-based CO_2 emission standards for affected fossil fuel-fired electric utility steam generating units and stationary combustion turbines (in lbs CO_2/MWh) that are equal to or lower than the CO_2 emission performance rates in the emission guidelines, then no additional demonstration is required beyond inclusion of the emission standards in the plan. Under this approach, compliance by affected EGUs with the emission standards will ensure that the CO_2 emission performance rates or the state rate-based CO_2 emission goal is achieved.

If a state chose to instead apply rate-based emission performance standards to individual affected EGUs, or to sub-categories of affected EGUs (such as fossil fuel-fired electric utility steam generating units and stationary combustion turbines), at a lb CO_2/MWh rate that differs from the CO_2 emission performance rates or the state's rate-based CO_2 goal, then a further demonstration is required that application of the CO_2 emission standards will achieve the CO_2 emission performance rates or state rate-based CO_2 goal in the emission guidelines. The state must demonstrate through a projection that the weighted average CO_2 emission rate of affected EGUs, when weighted by generation (in MWh), will be equal to or less than the CO_2 emission performance rates or the state's rate-based CO_2 emission goal. This projection must address both the interim period (including interim step periods 1-3, for 2022-2024, 2025-2027, and 2028-2029), and the final period (2030-2031, and subsequent two-year periods). The projection in a state plan must include the following key information, at a minimum:

- a summary of each affected EGU's anticipated future operation characteristics, including annual generation,

CO_2 emissions, capacity and capacity factors;

- planned retirements;
- anticipated use of ERCs to adjust the reported CO_2 emission rate of affected EGUs, including but not limited to, anticipated use (in MWh) by technology-type (e.g., wind, solar, demand-side EE), the physical location of the resources providing ERCs, and any other relevant information (e.g., power purchase agreements (PPAs) and other long-term power contracts); and an explanation, with calculation, of how these measures are being used in the projection to adjust the CO_2 emission rate of affected EGUs;
- expected electricity demand growth at the state or regional level, including the source and basis for these estimates (e.g., based on population growth, GDP, adoption of demand-side EE or other applicable factors); if demand growth is not from NERC, an ISO or RTO, EIA or other publicly available source, then the projection must include justification and assumptions that inform the demand growth used;
- expected fuel switching at affected EGUs;
- heat rate improvements; and
- any other applicable assumptions used in the projection.

Because electricity flows across state boundaries, single state plan demonstrations must explain any regional information considered in developing the assumptions. Multi-state plans or plans sharing common elements should use regional assumptions or demonstrate reconciliation of any inconsistencies between state-level assumptions.

(b) Demonstration for a mass-based emission standards state plan. Under the emission standards plan type, a mass-based emission budget trading program must be designed such that compliance by affected EGUs would achieve the state mass-based CO_2 goal. Under this approach, a state plan establishes emission budgets for affected EGUs during the interim and final plan performance periods that are equal to or lower than the applicable state mass-based CO_2 goals specified in the final emission guidelines. Compliance periods for affected EGUs are also aligned with the interim and final plan performance periods. This approach limits total CO_2 emissions from affected EGUs during the interim and final plan performance periods to an amount equal to or less than the state's mass-based CO_2 goal.

Under this approach, compliance by affected EGUs with the mass-based emission standards in a plan would ensure that the state achieves its mass-based CO_2 goal for affected EGUs. No further demonstration is necessary by the state to demonstrate that its plan would achieve the state's mass-based CO_2 goal.

For this type of plan, where the emission budget is equal to or less than the state mass CO_2 goal,[58] the EPA will assess achievement of the state goal based on compliance by affected EGUs with the mass-based emission standards, rather than reported CO_2 emissions by affected EGUs during the interim plan performance periods and final plan performance periods. This approach allows for allowance banking between performance periods, which is a typical design element for emission budget trading programs addressing GHG emissions.

(4) <u>State reporting requirements</u>. After consideration of the comments received regarding state reporting requirements, the EPA is finalizing for state plans using the emission standards approach that a state report is due to the EPA no later than the July 1 following the end of each reporting period. For the interim period (2022-2029) the EPA is finalizing the following interim reporting periods: interim step 1 covers the 3 calendar years 2022-2024; interim step 2 covers the 3 calendar years 2025-2027 and interim step 3 covers the 2 calendar years 2028-2029. A biannual state report is required starting in 2030 and beyond covering the 2 calendar years of each reporting period. The EPA believes this final reporting schedule will reduce the reporting frequency for states implementing the emission standards approach.

The state must include in each report to the EPA the status

[58] As specified for the interim plan performance period (including specified levels in interim steps 1 through 3) and the final two-year plan performance periods.

of implementation of emission standards for affected EGUs under the state plan, including current aggregate and individual CO_2 emission performance by affected EGUs during the reporting period. The state report must include compliance demonstrations for affected EGUs and identify whether affected EGUs are on schedule to meet the applicable CO_2 emission performance rate or emission goal during the performance periods and compliance periods, as specified in the state plan.

As discussed in more detail in section VIII.F, in each report during the interim period (2022-2029), the state must include an interim performance check. The interim performance check will compare the CO_2 emission performance level identified in the state plan for the applicable interim step period versus the actual CO_2 emission performance achieved by affected EGUs during the period. Starting in 2032, the biannual state report must include a final performance check to demonstrate that the state continues to meet the final CO_2 emission performance rates or state rate-based or mass-based CO_2 goal.

For states using the emission standards approach, if actual CO_2 emission performance by affected EGUs exceeds the specified level of CO_2 emission performance in the state plan by 10 percent or more during any of the specified interim step reporting periods or during a final plan reporting period (after 2030), the state report must include a notification to the EPA that corrective measures have been triggered. Corrective measures are discussed in detail in section VIII.F.

c. Additional components required for the state measures approach. The EPA is finalizing requirements that a final plan submittal using the state measures approach must contain the following components, in addition to the components discussed in section VIII.D.2.a.

(1) Identification of federally enforceable emission standards for affected EGUs (if applicable). If applicable, the state plan submittal must include any federally enforceable CO_2 emission standards that apply to affected EGUs, and demonstrate that those emission standards meet the requirements that apply in the context of an emission standards approach, discussed in the preceding section VIII.D.2.b. Specifically, the state plan submittal must demonstrate that each federally enforceable emission standard is quantifiable, non-duplicative, permanent and verifiable.

(2) Identification of backstop of federally enforceable emission standards. A state measures plan must include a backstop of federally enforceable emission standards for affected EGUs that fully achieve the CO_2 emission performance rates or the state's interim and final CO_2 emission goal if the state plan fails to achieve the intended level of CO_2 emission performance. The backstop emission standards could be based on the federal plan, using the federal plan regulations as a model rule. For the federally enforceable backstop, the state plan submittal must

identify the federally enforceable emission standards for affected EGUs, demonstrate that those emission standards meet the requirements that apply in the context of an emission standards approach, discussed in the preceding section, identify a schedule and trigger for implementation of the backstop that is consistent with the requirements in the emission guidelines and identify all necessary state administrative and technical procedures for implementing the backstop (e.g. how and when the state would notify affected EGUs that the backstop has been triggered). Aspects of the backstop are discussed in detail in section VIII.C.4.b.

(3) Identification of state measures. A state adopting a state measures plan approach must provide as a part of the supporting documentation of its plan submittal, a description of all the state enforceable measures the state will rely upon to achieve the requisite CO_2 emission performance rates or state goal, the applicable state laws or regulations related to such measures, and identification of parties or entities implementing such state measures. The state must also include in its supporting documentation the schedule and milestones for the implementation of the state measures. A state measures plan submittal that relies upon RE and demand-side EE programs and projects must also demonstrate in its supporting documentation that the minimum EM&V requirements apply to those programs and projects.

(4) Demonstration that the standards and/or measures are

projected to achieve the CO_2 emission performance rates or state CO_2 emission goal. A state plan submittal must demonstrate that the federally enforceable emission standards for affected EGUs, if included, and state measures, are sufficient to attain the CO_2 emission performance rates or state rate-based or mass-based CO_2 emission goal for the interim period of 2022-2029 and the final period of 2030 and beyond. The elements required in the state demonstration will vary depending on the design of the state plan, as described below in this section.

(a) Demonstration for a state measures state plan. A state measures plan submittal must demonstrate that the state measures, whether alone or in conjunction with any federally enforceable CO_2 emission standards, will achieve either the CO_2 emission performance rates or the state rate-based or mass-based CO_2 goals in the emission guidelines for the interim and final periods. This includes the interim period of 2022-2029, including interim step 1 2022-2024 period, interim step 2 2025-2027 period, and interim step 3 2028-2029 period (or alternative CO_2 emission performance step levels adopted by the state, provided they result in achievement of the CO_2 emission performance rates or state CO_2 emission goal during the 2022-2029 interim period), as well as the final period of 2030 and beyond.

A satisfactory demonstration of the future CO_2 performance of quantifiable and verifiable state-enforceable measures must use technically sound quantification methods that are reliable and replicable. The demonstration must be supported by the methods and measurement procedures by which the federally enforceable CO_2 emission standards for affected EGUs are reliably measured, if these standards are incorporated into the state measures state plan. In addition, the demonstration must include details about individual state-enforceable measures (or bundled measures), timing for implementation and future MWh impacts of these measures. The future performance of affected EGUs must be based on verifiable and quantifiable energy and emissions quantification methods accompanied with underlying analytical assumptions and verifiable data sources used to demonstrate future CO_2 performance by affected EGUs under this type of state plan.

A satisfactory state measures plan demonstration must include a state measures CO_2 performance projection that shows how the measures in the state plan, alone or in conjunction with federally enforceable CO_2 emission standards, will achieve the future CO_2 performance at affected EGUs. Elements of this projection must include the following for the interim and final periods:

- An explanation of the tools and emission quantification approaches used in the projection (described in section VIII.D.2.c.(4)(b).
- State Measures Plan CO_2 Performance Projection that

includes all state measures and/or emission standards in the state plan (see the State Plans Technical Support Document for details).

- Underlying assumptions used in the projection (as described below in sections VIII.D.2.c.(4)(b),(c) and (d).

(b) Emission quantification approaches and tools. The EPA received comments on whether we would require specific modeling tools and input assumptions. Commenters raised concerns that the EPA may require states to use proprietary models because many states do not have the financial resources to conduct their own modeling using utility dispatch models or capacity expansion models. The EPA is not requiring a specific type of emission quantification approach or model, as long as the one chosen uses technically sound methods that establish a clear relationship between electricity grid interactions of the state enforceable measures, affected EGU dispatch, generation cost and operations within the time frame outlined in these guidelines. Emission quantification methodologies could range from historical estimates using growth rate or statistical analysis to electric sector energy modeling. If a state chose to include supplemental material on emission baseline projections, then the emissions quantification method used for both the baseline projection and state measure plan scenario should be similar. A state should include an explanation of how the emission quantification method works and the associated tool(s) that employ the method, as well as an explanation for why the methodology and tool chosen is best suited for an electric sector analysis of affected EGUs for the interim period and final period. The results in the demonstration must be verifiable and reproducible using the documented assumptions described in the following paragraph.

The projections of EGU dispatch and generation can differ from the EPA's forecast in the RIA, but should have a clear relationship between future electricity demand, costs and generation capacity to establish the projected future CO_2 emissions from affected EGUs. The following assumptions demonstrating the relationship between the state measures and CO_2 emission performance of affected EGUs should be documented and explained: projected CO_2 emission rates in lbs/MWh; projected CO_2 emissions; projected generation at the EGU in MWhs; fuel prices, when applicable; heat rates for each affected EGU; wholesale electricity prices, when available; projected emission limits and/or rates as a result of environmental or economic constraints; planned retirements; planned new generation; fuel switches at affected EGUs; fixed operations and maintenance costs, when applicable; variable operations and maintenance costs, when applicable; and planning reserve margins, when applicable.

(c) <u>Elements of a rate-based state measures plan</u>. Under a rate-based state measures plan, MWh from state enforceable qualifying measures may be used to adjust the CO_2 emission rate of affected EGUs when demonstrating achievement of the CO_2 emission performance rates or the state rate-based CO_2 goal in the emission guidelines. The state plan would include the following key information, at a minimum, to demonstrate the rate-based state measures plan for affected EGUs are commensurate with the state's goal:

- a summary of each affected EGU's anticipated future operation characteristics, including annual generation, CO_2 emissions, capacity and capacity factors;
- planned retirements;
- a detailed description of the zero CO_2 emitting demand-side EE savings and RE generation (and any other qualifying MWh) from state measures that will be available for use in adjusting the reported CO_2 emission rates of affected EGUs, including, but not limited to, the amount of generation or savings by technology-type (e.g., wind, solar, EE), the physical location of the EE measures or RE generation, and any other relevant information (e.g., power purchase agreements (PPAs) and other long-term power contracts); and an explanation, with calculation, of how these measures are being used in the projection to adjust the CO_2 emission rate of affected EGUs;

- expected electricity demand growth at the state or regional level, including the source and basis for these estimates (e.g., based on population growth, GDP, adoption of demand-side EE or other applicable factors); if demand growth is not from NERC, an ISO or RTO, EIA or other publicly available source, then the projection must include justification and assumptions that inform the demand growth used;
- expected fuel switching at affected EGUs;
- heat rate improvements; and
- any other applicable assumptions used in the projection.

In the state plan demonstration, the state must show the calculation of this adjustment from these state enforceable actions at their affected EGUs either in aggregate or at each affected EGU. As specified in section VIII.G, the zero-emitting MWhs of EE and RE can be added to the denominator of the emission rate of the affected EGUs. The demonstration should illustrate this arithmetic adjustment for rate-based state measure plans.

(d) Elements of a mass-based state measures plan. Under a mass-based state measures plan, a state must demonstrate that the combined state-enforceable measures, along with any federally enforceable CO_2 emission standards for affected EGUs, if included, will achieve the state mass-based CO_2 goal. Because these measures could have varying degrees of impact on CO_2 emissions from affected EGUs, the approach a state chooses to quantify projected emissions impacts should have the capability to demonstrate how the combined state enforceable measures are impacting CO_2 emissions at affected EGUs so that the sum of emissions at all affected EGUs will be lower than or achieve the state's CO_2 emission goal for each specified time period in the emission guidelines. The EPA is not requiring a specific method or tool, but clear documentation of assumptions and explanation of methods used, as discussed in section VIII.D.2.c and in the State Plans Technical Support Document, must be included in a satisfactory demonstration.

(5) State reporting requirements. After consideration of the comments received regarding state reporting requirements, the EPA is requiring in this final rule for states using the state measures approach that an annual state report is due to the EPA no later than July 1 following the end of each calendar year during the interim period. This annual state report must include the status of implementation of federally enforceable emission standards (if applicable) and state measures and should include a report of the periodic programmatic milestones to show progress in program implementation. The programmatic milestones with specific dates for achievement should be appropriate to the state measures included in the state plan submittal.

As discussed in section VIII.F, for states using the state measures approach, the EPA is finalizing that at the end of each interim step period, the state must also include in their annual report to the EPA the corresponding emission performance checks. The interim performance checks will compare the CO_2 emission performance level identified in the state plan for the applicable interim step period versus the actual CO_2 emission performance achieved by the aggregate of affected EGUs.

Beginning with the final period, the state must submit biannual reports no later than July 1 after the end of each reporting period that includes an actual performance check to demonstrate that the state continues to meet the final CO_2 emission performance rates or state CO_2 goal.

If, at the time of the state report to the EPA, the state did not meet the programmatic milestones for the reporting period, or the performance check shows that actual CO_2 emission performance by affected EGUs exceeds the specified level of emission performance in the state plan submittal by 10 percent or more, the state must include in the state report a notification to the EPA that the backstop has been triggered and describe the steps taken by the state to inform the affected EGUs that the backstop has been triggered. In the event of such an exceedance under the state measures approach, the backstop federally enforceable emission standards for the EGUs must be effective within 18 months of the deadline for the state reporting to the EPA on plan implementation and progress toward the meeting the

CO_2 emission performance rates or state CO_2 emission goal. For example, if a state report due on July 1, 2025, shows that actual CO_2 emission performance by affected EGUs exceeds the specified level of emission performance for 2022-2024 in the state plan by 10 percent or more, the backstop federally enforceable emission standards for affected EGUs must be effective as of January 1, 2027.

(6) Supporting documentation.

(a) Demonstration that each state measure is quantifiable, non-duplicative, permanent, verifiable and enforceable. A state using the state measures approach, in support of its plan, must also include in the supporting documentation of the state plan submittal the state measures[59] that are not federally enforceable emission standards, and describe how each state measure is quantifiable, non-duplicative, permanent, verifiable, and enforceable with respect to an affected entity.

A state measure is quantifiable if it can be reliably measured, using technically sound methods, in a manner that can be replicated.

A state measure is non-duplicative with respect to an affected entity if it is not already incorporated as a state measure or an emission standard in another state plan or state

[59] "State measures" refer to measures that the state adopts and implements as a matter of state law. Such measures are enforceable only per applicable state law, and are not included in the federally enforceable state plan.

plan supporting material, except in instances where incorporated in another state as part of a multi-state plan. An example of a duplicative state measure would occur, for example, where a quantified and verified MWh from a wind turbine could be applied in more than one state's CAA section 111(d) plan to adjust the CO_2 emission rate of an affected EGU, except in the case of a multi-state plan where CO_2 emission performance is demonstrated jointly for all affected EGUs subject to the multi-state plan. This does not mean that measures in a state measure cannot also be used for other purposes. For example actions taken pursuant to CAA section 111(d) requirements can satisfy other CAA program requirements (e.g., Regional Haze requirements, MATS etc.) and state requirements (e.g., RPS).

A state measure is permanent if the state measure must be met for each applicable compliance period.

A state measure is verifiable if adequate monitoring, recordkeeping and reporting requirements are in place to enable the state to independently evaluate, measure and verify compliance with it.

A state measure is enforceable[60] if it: (1) represents a technically accurate limitation or requirement and the time period for the limitation or requirement is specified, (2) compliance requirements are clearly defined, (3) the affected

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[60] Under the state measures approach, state measures are enforceable only per applicable state law.

entities responsible for compliance and liable for violations can be identified, (4) each compliance activity or measure is practically enforceable in accordance with EPA guidance on practical enforceability,[61] and the state maintains the ability to enforce against violations and secure appropriate corrective actions.

The EPA will disapprove a state plan if the documentation is not sufficient for the EPA to be able to determine whether the state measures are expected to yield CO_2 emission reductions sufficient to result in the necessary CO_2 emission performance from affected EGUs for the CO_2 emission performance rates or state CO_2 emission goal to be achieved.

d. Legal basis for the components.

(1) General legal basis. Under section 111(d), state plans must "provide for the implementation and enforcement of [the] standards of performance." Similar language occurs elsewhere in the CAA. First, for SIPs, section 110(a)(1) requires SIPs to "provide for implementation, maintenance, and enforcement" of the

[61] The EPA's prior guidance on enforceability serves as the foundation for the types of measures that the EPA has found can be, as a practical matter, enforced. The EPA's guidance on enforceability includes: (1) September 23, 1987, memorandum and accompanying implementing guidance, "Review of State Implementation Plans and Revisions for Enforceability and Legal Sufficiency," (2) August 5, 2004, "Guidance on SIP Credits for Emission Reductions from Electric-Sector Energy Efficiency and Renewable Energy Measures," and (3) July 2012 "Roadmap for Incorporating Energy Efficiency/Renewable Energy Policies and Programs into State and Tribal Implementation Plans," Appendix F.

NAAQS. However, section 110(a)(2), unlike 111(d), details a number of specific requirements for SIPs that, in part, speak exactly to how a SIP should "provide for implementation, maintenance, and enforcement" of the NAAQS. We note that section 111(d) provides explicitly only that the "procedures," and not the substantive requirements, for section 111(d) state plans should be "similar" to those in section 110, and thus a substantive requirement in section 110(a)(2) is not an independent source of authority for the EPA to require the same for section 111(d) plans. However, when there is a gap for the EPA to fill in interpreting how a section 111(d) plan should "provide for implementation and enforcement of the] standards of performance," and Congress explicitly addressed a similar gap in section 110, then it may be reasonable for the EPA to fill the gap in section 111(d) using an analogous mechanism to that in section 110(a)(2), to the extent that the section 110(a)(2) requirement makes sense and is reasonable in the context of section 111(d). On the other hand, that Congress did not explicitly provide such details as are found in section 110(a)(2) indicates that Congress intended to give the EPA considerable leeway in interpreting the ambiguous phrase "provides for implementation and enforcement of [the] standards of performance."

For example, section 110(a)(2)(E)(i) explicitly requires states to provide necessary assurances that they have adequate personnel, funding and authority to carry out the SIP. Section 111(d), on the other hand, does not explicitly contain this requirement. Thus, there is a gap to fill with respect to this issue when the EPA interprets section 111(d)'s requirement that plans "provide for implementation and enforcement" of the standards of performance, and it is reasonable for the EPA to fill the gap by requiring adequate funding and authority, both because adequate funding and authority are fundamental prerequisites to adequate implementation and enforcement of any program, and because Congress has explicitly recognized this fundamental nature in the section 110 context.[62]

We note two other places where the CAA requires a state program to satisfy similar language regarding implementation and enforcement. First, section 112(l)(1) allows states to adopt and submit a program for "implementation and enforcement" of section 112 standards. Section 112(l)(5) further provides that the program must (among other things) have adequate authority to enforce against sources, and adequate authority and resources to implement the program. Second, section 111(c) provides that, if a state develops and submits "adequate procedures" for "implementing and enforcing" section 111(b) standards of performance for new sources in that state, the Administrator

[62] On the other hand, there are specific requirements in 110(a)(2) that are fundamental for SIPs, but would not make sense in the 111(d) context. For example, the specific requirement for an ambient air quality monitoring network in 110(a)(2)(B) is irrelevant in the 111(d) context. For a detailed discussion of the specific legal basis for each component, please see the Legal Memorandum for this final rule.

shall delegate to the state the Administrator's authority to "implement and enforce" those standards. The EPA has interpreted these ambiguous provisions in the EPA's "Good Practices Manual for Delegation of NSPS and NESHAPS" and recommended (in the context of guidance) that state programs have a number of components, such as source monitoring, recordkeeping, and reporting, in order to adequately implement and enforce section 111(b) or 112 standards. This again indicates it is reasonable for the EPA to fill a gap in section 111(d)'s language and similarly require source monitoring, recordkeeping, and reporting, as these are fundamental to implementing and enforcing standards of performance that achieve the state performance rates or goals.

Some commenters argued that states have primary authority over the content of state plans and that the EPA lacks authority to disapprove a state plan as unsatisfactory simply because it lacks one or more of these components. We disagree. The EPA has the authority to interpret the statutory language of section 111(d) and to make rules that effectuate that interpretation. With respect to the components of an approvable plan, we are interpreting the statutory phrase "provide for implementation and enforcement" and making rules that set out the minimum elements that are necessary for a state plan to be "satisfactory" in meeting this statutory requirement. This does not in any way intrude on the state's ability to decide what mix of measures should be used to achieve the necessary emission reductions. Nor does it intrude in any way on the state's ability to decide how to satisfy a component. For example, for legal authority, we are not dictating which state agencies or officials must specifically have the necessary legal authority; that is entirely up to the state so long as the fundamental requirement to have adequate legal authority to implement and enforce the plan is met.

In addition, the EPA has already determined in the 1975 implementing regulations that certain components, such as monitoring, recordkeeping, and reporting, are necessary for implementation and enforcement of section 111(d) standards of performance. 40 FR 53340, 53348/1 (Nov. 17, 1975). Thus, EPA's position here is hardly novel.

(2) <u>Legal issues with changes to affected EGUs</u>. In the proposed rulemaking, the EPA took the position that if an existing source is subject to a section 111(d) state plan, and then undertakes a modification or reconstruction, the source remains subject to the state plan, while also becoming subject to the modification or reconstruction requirements. 79 FR 34830, 34903-4. We noted that section 111(d) is silent as to this issue, which we took to grant us authority to provide a reasonable interpretation under the Supreme Court's decision in *Chevron U.S.A. Inc.* v. *NRDC*, 467 U.S. 837, 842-844 (1984). We stated two reasons to disallow existing sources to escape 111(d) through modification or reconstruction. First, if a source did so, that could prove

disruptive to the state plan. Second, allowing sources to do so could provide them an incentive to do so that would be contrary to the purposes of 111(d). We then asked for comment on "whether this interpretation is supported by the statutory text and whether this interpretation is sensible policy and will further the goals of the statute."

With respect to our request for comments on whether our proposed interpretation is supported by the statutory text, we received comments arguing that it violates the statute. The commenters noted that section 111(a)(6) defines "existing source" as "any stationary source other than a new source," and section 111(a)(2) defines "new source" to include stationary sources that are constructed or modified after "the publication of regulations (or, if earlier, proposed regulations) prescribing a standard of performance under [section 111] which will be applicable to such source." The comments concluded from this that the two categories are mutually exclusive, regardless of section 111(d)'s silence on the issue. The comments also noted that section 111(d)(1) only allows states to impose standards of performance in 111(d) plans on existing sources "to which a standard of performance under [111] would apply if such existing source were a new source," from which the comments inferred that states lacked authority under 111(d) to regulate sources that are regulated under 111(b).

We do not completely agree with these comments, which "prove too much." It is not the case that a source can never be both an existing source and a new source within the meaning of sections 111(a)(6) and 111(a)(2), respectively. First, a source that was a new source under 111(b) standards of performance for one pollutant can of course later become an existing source under 111(d) for another pollutant when the EPA promulgates 111(b) standards of performance and 111(d) emission guidelines for the second pollutant. Any other result would be illogical. Second, we have taken the position under section 129 (which has similar but not identical definitions) that a new source can subsequently become an existing source under revised 129(b) guidelines. E.g., 74 FR 51368, 51374-75 (Oct. 6, 2009). Thus, the comments' "plain meaning" argument fails to take into account context such as these.

However, we do agree that, in the particular context here, i.e. when section 111(d) emission guidelines are initially promulgated for existing stationary sources in response to corresponding section 111(b) standards of performance for the same pollutant, that the statute prohibits new sources (including under those particular 111(b) standards of performance from simultaneously being subject to state plans under those particular 111(d) emission guidelines. This interpretation gives meaning to the definition of "existing source" in section 111(a)(6) and is consistent with the definition of "new source" in section 111(a)(2). And, it is consistent with the historical treatment of modified and reconstructed sources in the section 111 program. The EPA plans to address ways to minimize disruption to state plans if such a modification or reconstruction were to take place.

We believe our final interpretation could reasonably be anticipated from our proposal notice. Although our notice proposed only a different interpretation of the statute, we did not indicate that the proposed interpretation was a settled matter (for example, based on previous EPA practice), and we invited comment on whether our interpretation was supported by the statute. Furthermore, we are basing our final position on the language of sections 111(a)(2) and 111(a)(6), which were quoted in our discussion of this exact issue in our proposal notice. 79 FR 34830, 34903/3. Thus, we gave adequate notice of the relevant provisions of the statute, and it could not be unfair surprise that sections 111(a)(2) and 111(a)(6) formed the basis of our ultimate position. Finally, there are a very limited number of potential interpretations of these provisions with respect to this issue; thus our final position could be reasonably anticipated.

(3) Legal issues regarding design, equipment, work practice or operational standards. In the proposal, the EPA asked for comment on three approaches to inclusion of design, equipment, work practice and operational standards in section 111(d) plans. 79 FR 34830, 34926/3 (June 18, 2014). Under the first approach, states

would be precluded from including these standards in section 111(d) plans unless the design, equipment, work practice or operational standard could be understood as a "standard of performance" or could be understood to "provide for implementation and enforcement" of standards of performance. We also asked, for the first approach, whether it was even possible, given the statutory language of 111(h), to consider a design, equipment, work practice or operational standard as a "standard of performance." Under the second approach, states could include design, equipment, work practice or operational standards in the event that it could be shown a "standard of performance" was not feasible, as set out in section 111(h). Under the third approach, a state could include design, equipment, work practice and operational standards in a 111(d) plan without any constraints. We also asked whether, if there was legal uncertainty as to the status of these standards, the EPA should authorize states to include them in their 111(d) plans with the understanding that if the EPA's authorization were invalidated by a court, states would have to revise their plans accordingly.

The EPA is finalizing the first approach. Specifically, a state's standards of performance (in other words, either the federally enforceable backstop under the state measures approach or the emissions standards under the emissions standards approach) cannot consist of (in whole or part) design, equipment, work practice or operational standards. A state may include such standards in a 111(d) plan in order to implement the standards of performance. For example, a state taking a mass-based approach may include in its 111(d) plan a limit on hours of operation on a particular affected EGU, but that operational standard cannot substitute for a mass-based limit on the affected EGU.[63]

This follows from the statute. First, section 111(h)(1) authorizes the Administrator, when it is not feasible for certain reasons (specified in 111(h)(2)) to prescribe or enforce a standard of performance, to instead promulgate a design, equipment, work practice or operational standard. If a standard of performance could include design, equipment, work practice or operational standards, such authority would be unnecessary. Second, 111(h)(5) states that design, equipment, work practice or operational standards "described in" 111(h) shall be treated as standards of performance for the purposes of the CAA. This creates a strong inference that standards of performance otherwise should not include design, equipment, work practice, or operational standards. Finally, the general definition of "standard of performance" in 302(l) is similar to the definition of "emission limitation" (or "emission standard") in 302(k), with the exception that the definition of "emission limitation" explicitly includes design, equipment, work practice and operational standards, but the definition of "standard of

[63] In particular, a state may include in its 111(d) state plan an emission standard that is reflective of the CO_2 performance resulting from operational standards the state imposes on an affected EGU.

performance" omits them. Thus, as with our discussion of the term "standard of performance" above in VIII.B.7.e(1), even if the general definition of "standard of performance" in 302(l) applies to 111(d), the omission of design, equipment, work practice, and operational standards in 302(l) confirms our interpretation that they cannot be a 111 "standard of performance" (except under the limited circumstances in 111(h)). We conclude that it is reasonable, and perhaps compelled, to interpret the term "standards of performance" in 111(d) to not include design, equipment, work practice and operational standards.

However, section 111(d) requires plans to "provide for implementation and enforcement of [the] standards of performance." This language does not explicitly prohibit a plan from including design, equipment, work practice and operational standards, and allows for them to be included so long as they are understood to provide for implementation of the standards of performance. If they are included, the 111(d) plan must still be "satisfactory" in other respects, in particular in establishing standards of performance that are not in whole or in part design, equipment, work practice, and operational standards.

(4) <u>Legal basis for engagement with communities</u>. As previously discussed, section 111(d)(1) requires the EPA to promulgate procedures "similar" to those in section 110 under which states adopt and submit 111(d) plans. Section 110(a)(1) requires states to adopt and submit implementation plans "after reasonable notice

and public hearings." The implementing regulations under 40 CFR 60.27 reflect similar public participation requirements with respect to section 111(d) state plans. The EPA is sensitive to the legal importance of adequate public participation in the state plan process, including public participation by communities. As previously discussed in this rule, recent studies also find that certain communities, including low-income communities and some communities of color, are disproportionately affected by certain climate change related impacts. Because certain communities have a potential likelihood to be impacted by state plans for this rule, the EPA believes that the existing public participation requirements under 40 CFR 60.23 are effectuated for the purposes of this final rule by states engaging in meaningful, active ways with such communities. By requiring states to demonstrate they have meaningfully engaged with affected communities potentially impacted by state plans as part of the state plan development process, states meeting this requirement will satisfy the applicable statutory and regulatory requirements regarding public participation.

3. Components of the federally approved state plan

In this action the EPA finalizes that, to be fully approved, a state plan submittal must meet the criteria and include the required components described above. The EPA will propose and take final action on each state plan submittal in the *Federal Register* and provide an opportunity for notice and comment. When a state plan submittal is approved by the EPA, the EPA will codify the approved 111(d) state plan in 40 CFR part 62. The following components of the state plan submittal will become the federally enforceable state 111(d) plan:

- Federally enforceable emission standards for affected EGUs
- Federally enforceable backstop of emission standards for affected EGUs
- Implementing and enforcing measures for federally enforceable emission standards including EGU monitoring, recordkeeping and reporting requirements
- State recordkeeping and reporting requirements

E. State Plan Submittal and Approval Process and Timing

1. Overview

In this action the EPA is finalizing that state plan submittals are due on August 31, 2016, which is 13 months after finalization of the emission guidelines. The EPA recognizes that due to state legislative schedules and rulemaking processes, coordination needed among states involved in multi-state plans, coordination with third parties, and the complex technical work needed to develop a state plan, states may not be able to develop a final plan submittal by 13 months after the final rule. However, various states have existing CO_2 reduction programs in place, such as RE and demand-side EE measures, as well as state and regional programs designed to reduce CO_2 pollution from EGUs.

Furthermore, state governments have already begun active discussions on how to address the final rule through policy forums, white papers and non-profit organizations. The EPA is also in the process of developing a federal plan that states may wish to use as a model rule. The EPA views these actions as positive steps that make the 13-month timeline achievable. In order to address the concern that 13 months is not sufficient time for states to prepare and submit a final plan submittal and to allow consistent timelines for both a single state and multi-state approach to state plan submittals, the EPA is also finalizing a plan submittal process that provides additional time for states that need it to submit a final plan submittal to the EPA after August 31, 2016. This approach involves the option that we refer to as an initial submittal, followed by submittal of a final state plan submittal no later than August 31, 2018, for both single state and multi-state plan submittals. During the initial outreach process as well as the public comment period on the proposed rule, stakeholders commented that additional time was needed to accommodate, among other things, state legislative and rulemaking schedules, coordination among states involved in multi-state plans, coordination with third parties, and the complex technical work needed to develop a state plan. The EPA recognizes that state administrative procedures can be lengthy, some states may need new legislative authority, and states planning to join in a multi-state plan will likely need more than

13 months to get necessary elements in place. Balanced against that concern, however, is the urgency of addressing CO_2 emissions and the fact that there are certain steps the EPA believes states can take within 13 months to set themselves on a clear path to adoption of a final plan.

For states wishing to participate in a multi-state plan, the EPA is finalizing three forms of submittal that states may choose for the submittal of a multi-state plan.

The EPA is finalizing its proposed approach where one multi-state plan submittal is made on behalf of all participating states. The joint submittal must be signed by authorized officials for each of the states participating in the multi-state plan and would have the same legal effect as an individual submittal for each participating state. The joint submittal must adequately address plan components that apply jointly for all participating states and for each individual state in the multi-state plan, including necessary state legal authority to implement the plan, such as state regulations and statutes. Because the multi-state plan functions as a single plan, each of the required plan components (e.g., plan emission goals, program implementation milestones, emission performance checks, and reporting) would be designed and implemented by the participating states on a multi-state basis.

The EPA is also finalizing two additional options it solicited comment on for multi-state plan submittals. First, states participating in a multi-state plan have the option of providing a single submittal — signed by authorized officials from each participating state — that addresses common plan elements. This option requires individual participating states to provide individual submittals that provide state-specific elements of the multi-state plan. The common multi-state submittal must address all relevant common plan elements and each individual participating state submittal must address all required plan components (including common plan elements, even if only through cross reference to the common plan submittal). Under this approach, the combined common submittal and each of the individual participating state submittals would constitute the multi-state plan submitted for EPA review. The joint common submittal must be signed by authorized officials for each of the states participating in the multi-state plan and would have the same legal effect as an individual submittal for each participating state.

Second, the EPA is finalizing an approach where all states participating in a multi-state plan separately make individual submittals that address all elements of the multi-state plan. These submittals would need to be materially consistent for all common plan elements that apply to all participating states, and would also address individual state-specific aspects of the multi-state plan. Each individual state plan submittal would need to address all required plan components.

These approaches will provide states with flexibility in addressing contingencies where one or more states submit plan components that are not approvable. In such instances, these options simplify the EPA's approval of remaining common or individual portions of a multi-state plan and help address contingencies during plan development where a state fails to finalize its participation in a multi-state plan, with minimal disruption to the submittals of the remaining participating states. These additional submittal approaches also facilitate multi-state plans where the participating states are coordinating the implementation of their plans but are not taking on a joint multi-state emission goal for affected EGUs. For example, states may seek to engage in a multi-state approach that links rate-based or mass-based emission trading programs through appropriate authorizations (e.g. reciprocity agreements, or state regulations) that allow affected EGUs to use emission allowances or RE/EE credits issued in one state for compliance with an emission standard in another state.

In order to avoid a multi-state plan becoming unapprovable due to one state submitting an unapprovable portion of a multi-state plan, withdrawing from the multi-state plan, or failing to implement the multi-state plan, states may include express severability clauses if their multi-state plan is able to stand without further revision if one of the situations described above occurs. The severability clause must specify how the remainder of the multi-state plan or individual state plan would continue to function with the withdrawal of a state or states, and may also include pre-specified revisions. The EPA will evaluate the appropriateness of such a clause as part of its review of the multi-state plan submittal.

2. State plan submittal and timing

The EPA implementing regulations (40 CFR 60.23) require that state plans be submitted to the EPA within 9 months of promulgation of the emission guidelines, unless the EPA specifies otherwise.[64] The EPA is finalizing that each state must submit a final plan submittal to the EPA by August 31, 2016, (13 months after the final rule). The state may submit a final plan submittal by this date, or seek an extension to submit a final plan by submitting an initial plan submittal. In this final rule the EPA is providing states with the option of up to a 2-year extension that will provide a total of 3 years for a state to develop and submit a final state plan to the EPA. To qualify for an extension of the August 31, 2016 deadline until August 31 2018, a state must submit an initial plan submittal by August 31, 2016, that documents the state’s plan for preparing a final plan submittal by 2018. The EPA is also finalizing that a state must submit one progress update by August 31, 2017.

The EPA notes that the current implementing regulations at 40 CFR part 60 do not specify who has the authority to make a

[64] 40 CFR 60.23(a)(1).

formal submission of the state plan to the EPA for review. In order to clarify who on behalf of a state is authorized to submit an initial plan submittal, 2017 update, final state plan (or negative declaration, if applicable), and any revisions to an approved plan, the EPA has included a requirement in this final rule mirroring that of the requirement in 40 CFR part 51 App. V.2.1.(a) with respect to SIPs that identifies the Governor of a state as the authorized official for submitting the state plan to the EPA. If the Governor wishes to designate another responsible official the authority to submit a state plan, the EPA must be notified via letter from the Governor prior to the 2016 deadline for plan submittal so that they have the ability to submit the initial or final plan submittal in the State Plan Electronic Collection System (SPeCS). If the Governor has previously delegated authority to make CAA submittals on the Governor's behalf, a state may submit documentation of the delegation in lieu of a letter from the Governor. The letter or documentation must identify the designee to whom authority is being designated and must include the name and contact information for the designee and also identify the state plan preparers who will need access to SPeCS discussed in section VIII.E.7. A state may also submit the names of the state plan preparers via a separate letter prior to the designation letter from the Governor in order to expedite the state plan administrative process. Required contact information for the designee and preparers includes the person's title, organization and email address. The EPA recommends this information be submitted early in the state planning process to allow sufficient time for completion of SPeCS registration so that those authorized to use the system are provided access.

An initial plan submittal must include the components of a final plan submittal described in section VIII.D. Based on these components, potential justifications for seeking extensions include, among other things, a state's required schedule for legislative approval and administrative rulemaking, the need for multi-state coordination in the development of an individual state plan, additional time needed for the development of RE or demand-side EE programs in low-income communities, and process and coordination necessary to develop a multi-state plan.

As previously discussed, because certain communities have a potential likelihood to be impacted by state plans, the EPA believes that the existing public participation requirements under 40 CFR 60.23 are effectuated for the purposes of this final rule by states engaging in meaningful, active ways with such communities. Therefore, as part of its overall evaluation of whether the initial submittal justifies granting an extension for submission of the final plan, the EPA is requiring that states seeking an extension until 2018 must actively engage with communities with a potential likelihood of being adversely impacted by state plans, including low income communities and communities of color, throughout the state plan development process. In order to demonstrate to the EPA that states are actively engaging with affected communities, states must provide in their initial plan submittal a summary of how they have been engaging with community stakeholders and how they intend to meaningfully engage with community stakeholders during the additional time (if an extension is granted) for development of the final plan. In particular, states must document meetings and interactions that they have had with affected communities. Furthermore, states in their initial plan submittal and 2017 update must show how they identified low income and communities of color that they are conducting meaningful community engagement with in the state plan development process.

For some recommendations on the steps that states could take to engage communities in a meaningful way, the agency recommends that states consult the EPA's *Interim Guidance on Considering Environmental Justice During the Development of an Action*. In this document, the EPA defines meaningful involvement, as ensuring that, "potentially affected community members have an appropriate opportunity to participate in decisions about a proposed activity that will affect their environment and/or health; the public's contribution can influence the regulatory agency's decision; the concerns of all participants involved will be considered in the decision-making process; and the decision-makers seek out and facilitate the involvement of those potentially affected."[65] Additionally, this guidance document also encourages those writing rules consider the positive impacts that a rulemaking will have on communities).[66] Another resource that the EPA recommends that states consult when devising their state plans is the Considering Environmental Justice in Permitting resources available on the agency's website.[67] Both of the resources discussed above will provide states with assistance on how to effectively engage communities in the rulemaking process.

The EPA recommends that as part of their meaningful engagement with affected communities, that states work with affected communities to ensure that they have a clear understanding of the benefits and potential adverse impacts that a state plan might have on their communities and that there is a clear process for states to respond to input from communities.

If no affected EGU is located within a state, the state must submit a letter to the EPA certifying that no such facilities exist by August 31, 2016.[68] The EPA will publish a notice in the *Federal Register* to notify the public of receipt of such letters.

If a state submits an acceptable initial plan submittal by August 31, 2016, as specified in the plan guidelines, then the

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[65] Interim Guidance on Considering Environmental Justice During the Development of an Action. http://www.epa.gov/environmentaljustice/resources/policy/ej-rulemaking.html. July 2010.
[66] Ibid.
[67] Considering Environmental Justice in Permitting. http://www.epa.gov/environmentaljustice/plan-ej/permitting.html#actions.
[68] 40 CFR 60.23(b).

deadline extension for submitting a final plan submittal that the state requested will be deemed granted. If the EPA determines that the initial plan submittal does not meet the guidelines, the EPA will notify the state by letter, within 90 days, that the agency cannot approve the extension request based the state's initial plan submittal as submitted. The EPA will notify a state by letter only if the initial plan submittal does not meet the guidelines. An extension for submitting a final plan submittal will be deemed granted if the EPA does not deny the extension request based on the initial plan submittal. The EPA has determined this approach is authorized by, and consistent with, 40 CFR 60.27(a) of the implementing regulations.

In the proposal, EPA proposed an initial 13 month submittal, with a 1-year possible extension for states submitting plans on their own and a 2-year possible extension for states submitting as part of a multi-state region. The EPA received substantive comment on the achievability of these proposed deadlines for state plan. Multiple commenters expressed concern that due to timing of legislative cycles (some of which are every 2 years), regulatory processes, and other necessary tasks, states would find it extremely difficult, if not impossible, to submit plans in 1 or 2 years, whether or not they were planning to submit as part of a multi-state region. The EPA agrees that a schedule shorter than 3 years will be extremely challenging for many — though not all - states. We note that the CAA provides multiple years for states to complete other types of plans, such as those under CAA section 110, that are similar (or less) in scope and complexity than these plans. In light of the comments received and in order to provide maximum flexibility to states while still taking timely action to reduce CO_2 emissions, in this final rule the EPA is allowing for an extension until 2018 for both individual and multi-state plans. This 2-year extension is contingent upon a state submitting a detailed description of steps already taken, a detailed description of additional actions to be taken in order to meet the 2018 plan submittal date and the initial 2022 compliance deadline and a schedule for those actions. This 2-year extension is also contingent upon the state submitting an acceptable 2017 update by August 31, 2017 that documents the state's continued progress towards meeting the 2018 submittal deadline. If the state does not submit an acceptable 2017 update by August 31, 2017, the state will have failed to meet the conditions for the 2-year extension and the EPA will develop a federal plan unless the state submits a final plan during this time. The EPA is also clarifying the requirements for approvable initial plan submittals and 2017 updates, which can be found in section VIII.E.3.

3. Components of an initial state plan submittal and 2017 update and approvability criteria

As noted, if a state is unable to prepare and submit a final plan submittal by August 31, 2016, the state must make an initial plan submittal by that date and may request up to a 2-year extension to submit a final plan. To be approved, the EPA is finalizing that the initial plan submittal must address all components of a final plan submittal, including identifying which components are not complete. For incomplete components, an approvable initial plan submittal must contain a comprehensive roadmap outlining the path to completion, including milestones and dates.

During the public comment period, multiple commenters stated that the proposed timeframe for states to submit an approvable initial state plan submittal was not achievable, citing, among other things, the amount of decisions needed to be made by a state or states, and that the EPA needed to clarify the requirements for submitting an approvable initial state plan submittal. Multiple commenters also expressed concern that the requirements for an approvable initial plan submittal required final decisions to be made by states, and that the initial plan submittal deadline was not enough time for states to make these decisions. In order to address the commenters' concerns, the EPA is finalizing that in order to be approvable, an initial state plan submittal must address all components of a final plan submittal, including identifying which components are not complete, and include the following information:

- All components of a final plan, including which components are not complete.

- A justification for seeking an extension.
- A description of the plan approach (e.g., single or multi-state, CO_2 emission performance rates or state CO_2 rate or mass emission goal)
- A commitment to maintain existing measures that limit or avoid CO_2 emissions (e.g., RE standards), at least until the final plan is approved.
- A comprehensive roadmap with a schedule and milestones for completing the plan, including progress to date in developing a final plan and steps taken in furtherance of actions needed to finalize a final plan.
- Demonstration of opportunity for public comment on submittal and response to significant comments, and meaningful engagement with affected communities likely to be impacted by the state plan.

As stated above, the EPA is finalizing that the initial plan submittal must address all components of a final plan submittal, including identifying which components are not complete. For incomplete components, an approvable initial plan submittal must contain a comprehensive roadmap outlining the path to completion, including milestones and dates.

The EPA proposed that approvable justifications for seeking an extension beyond 2016 for submitting a final plan include: a state’s required schedule for legislative approval and administrative rulemaking, the need for multi-state coordination in the development of an individual state plan, or the process and coordination necessary to develop a multi-state plan. In this final rule, the EPA is finalizing these as acceptable justifications for seeking an extension beyond 2016. Although legislation and/or regulations do not need to be passed prior to the initial plan submittal in order to be granted an extension, the initial plan submittal must include any concrete steps the state has already taken on legislation and/or administrative rulemaking and detail what the remaining steps are in those processes before a final plan submittal can be submitted. The EPA also sought comment on other circumstances for which an extension of time would be appropriate, and also whether some justifications for extensions should not be permitted. Commenters stated that states should be able to seek extensions whenever an extension can be reasonably justified, and that the EPA should take at face value states' good faith efforts by accepting any state assertion that more time is needed to develop a plan unless there is clear evidence to the contrary. The EPA does not agree with the assertion that any reason provided by a state should automatically be deemed as an acceptable justification for being granted an extension, but agrees there may be appropriate justifications states may submit in addition to the ones described in this final rule. The EPA is not finalizing other justifications in this final rule, however, if a state submits a justification not listed here, the EPA will determine whether such submission constitutes an appropriate justification during review of the initial state plan submittals.

For descriptions of plan approaches, states must include a basic outline of the approach used to meet the state's CO_2 emission goals or the CO_2 emission performance rates. This should include, at a minimum, whether the state is choosing the option of the CO_2 emission performance rates, a rate-based CO_2 goal, or a mass-based CO_2 goal, and whether the state is pursuing a single-state or multi-state plan. Stakeholders commented that states will not be far enough along in the rule development process to have made these decisions. Commenters also stated that many state legislatures would need to pass legislation giving state environmental agencies legal authority and direction before they could begin to make decisions such as rate or mass-based approach or single or multi-state plan submittal. In order to address the commenters' concerns, the EPA wishes to clarify that state approaches in the initial state plan submittal do not need to be final and/or formalized through a state legislature, and that states may opt to pursue more than one approach at the same time. In order to fulfill the requirement for a description of the plan approach, the initial plan submittal may include the various compliance options a state or group or states is exploring and a detailed schedule outlining the process for making decisions necessary to meet the deadline for final plan submittal.

The EPA received substantive comment regarding the potential adverse consequences for states pursuing a multi-state approach and receiving an extension until 2018, where, for various reasons, a state or states then decide(s) to back out of the multi-state plan and pursue the single state approach. Commenters viewed this as being potentially problematic since, as proposed, a single state could only receive an extension until 2017, and if a multi-state plan effort does not work out the deadline for seeking the extension until 2017 would have passed. Finalizing a 2-year extension that is available for any state, whether they are pursuing an individual state plan or a multi-state plan resolves the commenters' concern about conflicting extension deadlines if states involved in a multi-state effort decide not to pursue the multi-state approach.

In order for a state's initial plan submittal to be approvable, the EPA is finalizing that the initial submittal must contain a commitment to maintain existing measures, such as RE standards and demand-side EE programs, at least until the final plan is approved. The EPA could not in good faith agree with a state's rationale for needing more time to develop a final state plan while at the same time the state was removing already in place measures that reduce CO_2 emissions from EGUs.

An initial state plan submittal must also include a description of the progress a state has made in the development of a final plan submittal as well as a comprehensive roadmap for completing the plan. This includes a schedule with milestones and dates. The milestones should outline the state’s path to submitting a final plan by August 31, 2018.

The EPA is finalizing the public comment requirements that were outlined in the proposal for initial plan submittals. Prior to submittal to the EPA, the state must provide an opportunity for public comment on a substantial draft of its initial plan submittal. This public comment opportunity will not be governed by the procedural requirements of the implementing regulations that apply to the state’s adoption of a final plan, such as the requirement that the state hold a public hearing. 40 CFR 60.23(c)-(f). An initial plan submittal might not include any legally enforceable provisions that the state would have adopted through its administrative or legislative processes, which generally provide for public input. Therefore, to ensure that the public has an opportunity to understand and inform the initial plan submittal, the final rule requires that prior to submittal on August 31, 2016, the state must have provided a reasonable opportunity for public comment on a substantial draft of the initial plan submittal, with notice to the EPA of that comment period.

The EPA can use this comment opportunity to advise the state whether it is on track to submit an approvable initial plan submittal. The comment period on the initial plan submittal is only one opportunity the EPA has to assist a state in the state plan development process. The EPA has historically worked with states throughout the state plan development process to help ensure that the state plan is approvable once submitted to the EPA, and expects this level of engagement with states to continue for this final rule. When the state submits its initial plan submittal, it must provide the EPA with a response to any significant comments it received on issues relating to the approvability of the initial plan so that the EPA can fully assess whether it is approvable.

For states participating in a multi-state program, the initial plan submittal must include the elements described above as well as any executed agreements among the participating states and a road map for both design of the multi-state program and its implementation at the state level. A multi-state initial plan submittal should also address situations where states may join together on only certain elements, such as RE, or standards on subsets of EGUs.

In this final rule, the EPA is allowing states up to 3 years to submit a final plan. This is contingent upon submitting an acceptable initial plan submittal and 2017 update. The 2017 updates will ensure that a state is making continuous progress on its initial plan and that a state is on track to meet the final plan submittal deadline of August 31, 2018. The EPA is requiring that the 2017 update must contain the following components:

- A summary of the status of each component of the final plan, including an update from the 2016 initial plan submittal and a list of which components are not complete.

- A commitment to a plan approach (e.g., single or multi-state, rate or mass emission performance level), including draft or proposed legislation and/or regulations.
- An updated comprehensive roadmap with a schedule and milestones for completing the plan, including progress to date in developing a final plan and steps taken in furtherance of actions needed to finalize a final plan.

In order to assess if a state is on track to submit a final plan by the 2018 extension deadline, the EPA is requiring that the 2017 update must contain a summary of all components of a final plan, including a progress update on any incomplete components from the initial plan submittal, and a list of which components are still not complete. This progress update must demonstrate that state has met the milestones and dates it outlined in its initial plan submittal. If a state has not met a milestone and date that it set in the initial plan submittal, or is not on pace to meet a future date, the state may revise its schedule in the 2017 update, provided that the schedule meets the 2018 deadline for final plan submittal.

The EPA is also requiring that the 2017 update include a commitment to the type of plan approach the state will take in the final plan submittal. During the public comment period, many commenters stated that legislative action would be required to enact this final rule at the state level, and that the proposal did not provide enough time for legislative action or other regulatory actions needed for a state to be granted an extension. In order to respond to these comments, the EPA clarified that proposed or passed legislation or regulations are not required in the initial plan submittal. While a state may pursue multiple types of state plans in the initial plan submittal, the EPA is requiring that the state commit to one approach in the 2017 update. This commitment must include draft or proposed legislation or regulations that must become final at the state level prior to submitting a final plan submittal to the EPA. While commenters expressed concern with not being able to have legislation enacted in time to receive an extension until 2018, the EPA has determined that 2 years is a reasonable timeframe for a state to decide on the type of approach it will take in the final plan submittal and to draft legislation or regulations for this approach.

Finally, the EPA is requiring that the 2017 update include an updated comprehensive roadmap with a schedule and milestones for completing the plan. Similar to the requirement that the 2017 update must include all components of a final plan, the update must include a demonstration that the state met the milestones for submitting a final plan that were outlined in the initial plan submittal. For any milestones that were not met, the state must provide a justification for not meeting the milestone and an updated schedule that demonstrates that the state is still on pace to meet the 2018 final plan submittal deadline.

The EPA will assess a state's 2017 update and, similar to the process for the initial plan submittal, notify the state within 90 days if the EPA determines that the state is not likely or able to meet the 2018 final plan submittal deadline. In the event that the EPA makes this determination for a state, the EPA will begin the federal plan development process to enforce and implement in the state.

4. Process for EPA review of state plans

Our proposal laid out the basic steps for EPA's review and action on submitted state plans and, at some length, discussed the required components of state plans, as further described in the preceding sections. We received a number of thoughtful and helpful comments on these issues. We are finalizing the basic requirements in this rule and are proposing, in the companion proposed federal plan under section 111d, some additional procedural elements we believe will be helpful to states, stakeholders and the EPA moving forward.

Following the August 31, 2016 deadline for state plan submittals, the EPA will review plan submittals for approvability. For a state that submits an initial plan submittal by August 31, 2016, and requests an extension of the deadline for the submission of a final state plan submittal, the EPA will determine if the initial plan submittal meets the minimum requirements for an initial plan submittal. If the initial plan submittal meets the minimum requirements specified in the emission guidelines, the state’s request for a deadline extension to submit a final plan submittal will be deemed granted, and the final plan submittal must be submitted to the EPA by no later than August 31, 2018.

After receipt of a final plan submittal, the EPA will review the plan submittal and, within 12 months, approve or disapprove the plan through a notice-and-comment rulemaking process, similar to that used for approving SIP submittals under section 110 of the CAA. The implementing regulations currently provide for the EPA to act on a final plan within 4 months after the deadline for submission, which is consistent with versions of section 110 prior to the 1990 Amendments to the CAA. 40 CFR 60.27(b). To be consistent with the current version of section 110, the EPA intends to adopt a timeline of 12 months to review final plan submittals upon receipt of complete submittals, as is generally consistent with the timing requirements of section 110 with respect to complete SIP submittals. Such a timeline would also provide the EPA with adequate time for review and rulemaking procedures, and ensuring an opportunity for public notice and opportunity for comment. We note, however, that we did not propose this timeline for review and action on state plans in our proposal, and, in particular, starting the 12 month review period from the date of receipt of a complete submission.[69] Therefore, we intend to propose the appropriate revisions to the implementing regulations as part of the upcoming federal plan proposal for section 111(d).

In addition, while the CPP proposal and this final rule lay out in considerable detail the required components of a state plan, the EPA believes that it would also be helpful to include in the rule a completeness determination process, similar to that used for SIP submittals in section 110, which will allow the EPA to determine whether a final plan submittal contains the components necessary to enable the EPA to determine through notice and comment rulemaking whether such submittal complies with the requirements of section 111(d). This is a procedural requirement under CAA section 110(k)(1), and the EPA believes this requirement is appropriate to establish under section 111(d)'s direction of the EPA to prescribe through regulations a procedure similar to that provided by section 110. However, because the EPA did not propose such regulations as part of the proposal for this action, the EPA intends to do so as part of the upcoming Federal Plan proposal for section 111(d). The EPA notes the components of state plans as laid out in section VIII.D and the final rule are the requirements for a state plan submittal,

[69] The EPA proposed 12 months after the date required for submission of a plan or plan revision to approve or disapprove such plan or revision or each portion thereof.

and therefore states have the necessary information at this time to develop state plans. The upcoming completeness criteria will not add to or change these required components, but only allow the EPA to identify whether there are absent or insufficient components in the plan submittal that would render the EPA unable to act on such submittal because it is incomplete. As will be further explained in the upcoming Federal Plan proposal, a determination by the EPA that a plan submittal is incomplete has the effect of a state having a still-pending statutory obligation to submit a plan that meets the requirements of section 111(d).

The EPA is planning to propose an amendment to the section 111(d) implementing regulations that will add the partial approval/disapproval and conditional approval mechanisms in section 110(k)(3) and (4) to the procedure for acting on section 111(d) plans. The input the agency got in response to the proposal for these guidelines indicated that the flexibility provided by these mechanisms could be useful getting state plans in place. So, the EPA expects to propose to amend the implementing regulations as part of the rulemaking for the federal 111(d) plan. The EPA is not taking final action on these changes in this action.

Deferring our action on partial approval/disapproval and conditional procedures does not create any issue with finalizing this rule. These procedural adjustments will only come into play after states have submitted their plans and the EPA is required to act on them. Until then, the EPA believes that every plan is submitted with the intent to be fully approvable and there is no need for states to rely on the possibility of these procedures when developing their plans. Conditional approval and partial approval/disapproval should be used to deal with approvability issues that arise despite the best efforts of states and the EPA to work together to make sure a submittal in the first instance is fully approvable. The EPA plans to finalize any changes in the implementing regulations before the EPA is required to act on state submittals, so that the EPA and states will have appropriate flexibility in the plan approval process.

5. Failure to submit a plan

If a state fails to submit a final plan submittal by the applicable deadline, or submits a final plan the EPA determines to be incomplete, the EPA will notify the state by letter of its failure to submit. The EPA will publish a *Federal Register* notice informing the public of its finding of failure to submit. Upon a finding of failure to submit for a state, a statutory clock will run requiring the EPA to promulgate a federal plan for such state no later than 2 years after the EPA makes the finding unless the state submits, and the EPA approves, a state plan during this time.

6. State plan modifications

a. Modifications to an approved state plan. During the course of implementation of an approved state plan, a state may wish to update or alter one or more of the enforceable measures in the state plan, or replace certain existing measures with new measures. The EPA received broad support for allowing states to submit modifications to approved state plans. In this rulemaking, the EPA is finalizing that a state or states may revise its state plan. Consistent with the timing for final plan submittals originally submitted by states, the EPA will act on state plan revisions within 12 months of a complete submittal. The EPA expects that the long compliance timeframes in this final rule and flexibility provided to states in developing state plans will lessen the need for modifications to approved state plans.

The EPA solicited comment on whether, for new projections of emission performance, the projection methods, tools, and assumptions used should match those used for the projection in the original demonstration of plan performance, or should be updated to reflect the latest data and assumptions, such as assumptions for current and future economic conditions and technology cost and performance. Comments received on this topic were generally supportive of allowing the use of updated data in state plan modifications, citing that states should have the ability to determine whether the original data and assumptions or updated data and assumptions are appropriate. The EPA is finalizing that new projections of emission performance, the projection methods, tools, and assumptions do not have to match those used for the projection in the original demonstration of plan performance; they can be updated to reflect the latest data and assumptions, such as assumptions for current and future economic conditions and technology cost and performance.

b. Modifications to interim and final CO_2 emission goals. As discussed in section VII, the final rule specifies that the state interim and final CO_2 emission goals may be adjusted to address inventory changes within a state's fleet. If these changes occur before a state submits its initial or final plan, the state should indicate in its submittal the circumstance that necessitates the goal adjustment and the revised interim or final CO_2 emission goal. If the circumstances occur after a state has an approved plan, a state must submit a modification to its approved plan. The plan revision submittal must indicate the circumstance that necessitates the goal adjustment, the revised interim and/or final CO_2 emission goal, and the adjustments to the enforceable measures in the plan.

As discussed in more detail in section VIII.H, the final rule has several measures to ensure that it does not interfere with the industry's ability to maintain reliability. One such measure is that if a state cannot address a reliability issue within the boundaries of an approved state plan, the state can submit a request to the EPA to modify the state plan. See section VIII.H for a more detailed discussion of this issue.

7. Plan templates and electronic submittal

The EPA is finalizing the requirement for states to electronically submit a negative declaration, state plan submittals, including any supporting materials that are part of a state plan submittal and any state reports required by the state plan. The rule provides that files that are submitted to the EPA in an electronic format may be maintained by states in an electronic format. The submission of the information by the authorized official must be in a non-editable format. In addition to the non-editable version, the EPA is also requiring that all plan components designated as federally enforceable must be submitted in an editable version as well, as discussed below.

a. Submittal of an editable version of federally enforceable plan components. To ensure that the EPA has the ability to identify, evaluate, merge, update and track federally enforceable plan components in a timely and comprehensive manner, the EPA is requiring states to submit an editable copy of the specific plan components in their submittal that are designated as federally enforceable, either effective upon the EPA plan approval or as a state plan backstop measure. The editable version is in addition to the non-editable version. Examples of editable file formats include Microsoft Word, Apple Pages and WordPerfect.

b. Plan revisions. Following initial plan approval, states shall provide the EPA with both a non-editable and editable copy of any submitted revision to existing approved federally enforceable plan components, including state plan backstop measures. The editable copy of any such submitted plan revision must indicate the changes made, if any, to the existing approved federally enforceable plan components, using a mechanism such as redline/strikethrough. This approach to identifying the changes made to the existing federally enforceable plan components is consistent with the criteria for determining the completeness of SIP submissions set forth in Section 2.1(d) of Appendix V to 40 CFR part 51.

It is the EPA's experience that electronic submittal of information has increased the ease and efficiency of data submittal and data accessibility. The EPA is developing the SPeCS, a web accessible electronic system to support this requirement that will be accessed at the EPA's Central Data Exchange (CDX) (http://www.epa.gov/cdx/). The EPA will pre-register authorized officials and plan preparers in CDX. See section VIII.E.2 for additional information on the pre-registration process for authorized officials and plan preparers. Detailed instructions for accessing CDX and SPeCS will be outlined in the "111(d) SPeCS User Guide: How to submit state 111(d) plan material to EPA" which will be available on the EPA's Clean Power Plan Toolbox for States. The EPA will provide SPeCS training for states prior to the state plan submittal due date.

Once in CDX, SPeCS can be selected from the Active Program Service List. The preparer (e.g., state representative compiling a state plan submittal) assembles the submission package. The preparer can upload files and complete electronic forms. However, the preparer may not formally submit and sign packages. Only registered authorized officials may submit and sign for the state with the exception of draft submittals. The EPA's intent is to allow submittal of draft plans or parts of plans for early EPA review prior to formal submission by the authorized official and will allow preparers, as well as authorized officials, to submit draft documents. The authorized official will be able to assemble submission packages and will be able to modify submission packages that a preparer has assembled. The key difference between the preparer and the authorized official is that the authorized official can submit and sign a package for formal EPA review using an electronic signature. In the case of a multi-state plan, each participating state's authorized official must provide an electronic signature.

The process has been designed to be compliant with the Cross-Media Electronic Reporting Rule (CROMERR), under 40 CFR part 3, which provides the legal framework for electronic reporting under all of the EPA's environmental regulations. The framework includes criteria for assuring that the electronic signature is legally associated with an electronic document for the purpose of expressing the same meaning and intention as would a handwritten signature if affixed to an equivalent paper document. In other words, the electronic signature is as equally enforceable as a paper signature. For more information on CROMERR, see the Web site: http://www.epa.gov/cromerr/. States who claim that a state plan submittal or supporting documentation includes confidential business information (CBI) must submit that information on a compact disk, flash drive, or other commonly used electronic storage media to the EPA. The electronic media must be clearly marked as CBI and mailed to U.S. EPA/OAQPS/CORE CBI Office, Attention: State and Local Programs Group, MD C539-01, 4930 Old Page Rd., Durham, NC 27703.

The EPA received a number of comments on the electronic submittal of state plans. Some commenters preferred the option to submit electronically rather than the requirement to do so. In the final rule, for the reasons discussed below, the EPA is requiring electronic submittal of state plans and not allowing alternate options for plan submittal (e.g. paper submittal).

Requiring electronic submittal is in keeping with current trends in data availability and will result in less burden on the regulated community. Electronic submittal will facilitate two-way business communication between states and the EPA, will guide states through the submittal process to ensure submission of all required plan components, and will enable states to submit proposed plans to the EPA electronically for early EPA comments. Electronic submittal will also facilitate, expedite and promote national consistency in the EPA’s review of state plans and promote transparency by providing stakeholder-specific access to updated information on state plan status and posting of plan requirements for viewing by the public, government regulators and regulated entities. The EPA recently implemented an electronic submittal process for SIPs under CAA section 110 and continues to explore opportunities to increase the ease and efficiency with which states and the regulated community can meet regulatory data submittal requirements. In summary, the EPA believes electronic submittal will be enormously beneficial in terms of improving coordination and cooperation between the EPA and its state partners in developing approvable state plans.

In the proposal, the EPA requested comment on the creation of templates for initial and final state plan submittals. Multiple commenters requested the EPA provide state plan templates. One commenter requested templates for different plan designs (e.g. a mass-based trading framework, a rate-based trading framework, multi-state compliance and a utility-based portfolio approach) and for specific plan components (e.g. how to incorporate a state RE standard and an EE program into a state plan, how to assess the emission reductions delivered by RE and EE). The EPA has decided not to develop templates for state plan submittals at this time given the broad range of approaches states may take in preparing individual or multi-state plans. However, the EPA does believe that states may use the Federal Plan as a template when preparing state plan submittals. The EPA will continue extensive outreach to states and work closely with states on the need for additional tools and guidance to facilitate the development of approvable state plans.

8. Legal issues regarding state plan process

Section 111(d)(1) requires the EPA to promulgate procedures "similar" to those in section 110 under which states adopt and submit 111(d) plans. The EPA has interpreted this provision previously in the implementing regulations found in 40 CFR part 60 subpart B. As discussed above, the EPA intends that planned revisions to the part 60 implementing regulations will clarify (among other things) whether certain procedures are appropriate for the EPA's action on 111(d) state plans, and if so, precisely how those procedures should apply. The EPA is proposing these revisions to the 111(d) implementing regulations in the notice of proposed rulemaking for the federal plan being issued concurrent with this final rule. In this section we discuss the legal basis for procedures that the EPA is finalizing in this action: initial plan submittals, extensions, and plan revisions.

First, we generally discuss the ambiguous word "similar." "Similar" does not have an identical meaning as the word "same." Webster's Third New International Dictionary defines "similar" as "having characteristics in common, very much alike" or "alike in substance or essentials." Webster's Third New International Dictionary 2120 (1993). On the other hand, "same" is defined as "resembling in every way, not different in relevant essentials," "conforming in every respect," or "corresponding so closely as to be indistinguishable." *Id.* at 2007.

Thus, had Congress intended that the procedures for section

111(d) plans be indistinguishable from those in section 110, Congress knew how to say so. *See, e.g.*, 36 U.S.C. § 2352(b)(2)(B) ("same procedures"). And had Congress intended that the procedures for section 111(d) plans be as close as possible to those in section 110, Congress knew how to say that. *See, e.g.*, 38 U.S.C. § 4325(c) (agency "shall ensure, *to the maximum extent practicable, that the procedures are similar* to" certain other procedures). Therefore, Congress must have intended to give the EPA leeway to create procedures for section 111(d) state plans that somewhat vary from those in section 110, so long as the section 111(d) procedures are reasonably tied to the purpose and text of section 111(d). In other words, "similar" creates a gap in the statute that the EPA may reasonably fill.

a. <u>Initial plan submittals and extensions</u>. Section 110 does not provide for initial plan submittals. As explained above, though, we are not bound under section 111(d)(1) to follow exactly the same procedures. Initial plan submittals in this instance are a reasonable gap-filling device. As explained in our proposal, certain aspects of section 111(d) plan development for these particular guidelines warrant our creation of this device.

With respect to the timing of initial plan submittals, final submittals, and extensions, we note that section 110(a)(1) provides that states should adopt and submit SIPs that provide for implementation, maintenance, and enforcement of the NAAQS within 3 years, or such shorter period as the Administrator may prescribe. Section 110(a)(1) does not provide any particular factors for the Administrator to consider in prescribing a shorter period. Thus, the EPA's prescription of a shorter period for either an initial plan submittal or a final plan submittal is consistent with the discretion granted in section 110(a)(1). We also note that section 110(b) provides for extensions of up to 2 years for plans to implement secondary NAAQS, that other provisions in part D provide for extensions of due dates of attainment plans in certain circumstances, and that the section 111(d) implementing regulations provide for extensions generally. We conclude, in view of the above discussion of "similar," that the device of initial plan submittals and extensions of due dates as proposed is a reasonable procedure that, while not identical to the procedures in section 110, is still similar.

Some commenters argued that the 1-year period for initial plan submittals and, even assuming an extension, the additional 1- to 2-year period for final submittals were unreasonable, particularly in light of the possibility that some state legislatures might need to act to provide adequate legal authority for these particular plans. We are not finalizing the 1-year extension for single state submittals, and we have addressed concerns about legal authority for the initial plan submittals by allowing states to identify remaining legislative action in those submittals.

With respect to the overall period of up to 3 years for submittals, we continue to find it reasonable and consistent with other deadlines in the CAA. First, section 110(a)(1) requires states to submit a plan for implementation, maintenance, and enforcement of new NAAQS within 3 years of promulgation of that NAAQS. This is true even if the EPA promulgates a NAAQS for a previously non-criteria pollutant. In that case, it is possible and even likely that at least some state agencies will lack statutory authority to regulate the new pollutant. Nonetheless, Congress dictated that states should submit section 110(a)(1) plans within 3 years.

Furthermore, we note that under subpart 1 of Part D of Title 1, attainment plans are generally due no later than 3 years after designation of a nonattainment area, and under other subparts of Part D, plans are due even more quickly. For example, under subpart 4, attainment plans for particulate matter are generally due 18 months after designation, and under subpart 5, the same deadline applies for attainment plans for sulfur oxides, nitrogen dioxide and lead. While developing attainment plans may not require states to seek additional legislative authority, in terms of complexity they are similar to section 111(d) plans for this guideline. In general, attainment plans must contain (among other things) a comprehensive inventory of sources of the relevant pollutant and its precursors (which in populated areas can be very numerous), control measures for those sources (including individualized control measures for the larger sources), and modelled demonstrations of attainment (which in some instances requires photochemical grid modeling). Thus, it is reasonable to have the same timeline for these section 111(d) plans as Congress generally provided for attainment plans in section 172(b).

b. State plan modifications. Section 110(l) provides for states to revise their SIPs, as does 40 CFR 60.28 for section 111(d) plans. Section 110(l) also sets out a standard for revisions: it prohibits the EPA from approving a SIP revision that would interfere with any applicable requirement concerning attainment or reasonable further progress, or any other applicable requirement of the CAA. Under the existing section 111(d) implementing regulations, the Administrator will disapprove section 111(d) plan revisions as unsatisfactory when they do not meet the requirements of subpart B to part 60. See 40 CFR 60.27(c)(3). However, the implementing regulations do not set forth a substantive standard like that in section 110(l).

Section 111(d)(1) does not mention revisions (except indirectly through the reference to section 110) and, therefore, does not explicitly provide any substantive requirements for them. There is, therefore, a gap in the statute that the EPA may reasonably fill. It is reasonable, at a minimum, that the state plan as revised should continue to provide for implementation and enforcement of the standards of performance, and to achieve the CO_2 emission performance rates or state CO_2 emission performance goal. This is analogous to the substantive requirements of section 110(l), which as explained above for section 110(a)(2), we may consider in determining how to reasonably fill statutory gaps for section 111(d) plans.

In our proposal, we proposed that certain revisions to state plans under these emission guidelines, those that revised enforceable measures for affected EGUs, should satisfy some additional conditions. First, the state should demonstrate that the plan continues to achieve the CO_2 emission performance rates or state CO_2 emission performance goal. We proposed that this demonstration might be simple for minor revisions, but for major revisions a more complete demonstration may be required. We are finalizing this proposal. As legal basis for this position, we note that a demonstration is necessary to show that a state plan provides for implementation of standards of performance that achieve the CO_2 emission performance rates or state CO_2 emission performance goal, and as explained above we can reasonably require the same of revisions.

It is also reasonable to tailor the requirements of the demonstration to the magnitude of the revision. The EPA has taken a similar approach to tailoring the requirements for a technical demonstration that, under section 110(l), a SIP revision does not interfere with any applicable requirement concerning attainment of the NAAQS. If a SIP revision does not relax the stringency of any SIP measure, then the demonstration is simple. If the SIP revision does relax the stringency of SIP measures, then a qualitative or quantitative analysis may be necessary to show non-interference, depending on the nature of the revision, the current air quality in the area, and other factors.

Finally, we proposed that revisions "should not result in reducing the required emission performance for affected EGUs specified in the original approved plan. In other words, no 'backsliding' on overall plan emission performance through a plan modification would be allowed." 79 FR 34917/1. We received adverse comments that this standard did not have a basis in section 111(d). According to commenters, since the standard for EPA approval of a section 111(d) plan is whether the plan is satisfactory in establishing and providing for implementation and enforcement of standards of performance that achieve the performance emission rates or goal, the same standard should apply to revisions. In other words, the standard for revisions should be whether the plan as revised is satisfactory. We believe that our proposal was unclear as to this point and we agree that the same standard for revisions should be the same as for submittals. We have finalized this position.

F. State Plan Performance Demonstrations

This section describes state plan requirements related to compliance periods, monitoring and reporting for affected EGUs; plan performance demonstrations; and consequences if the CO_2 emission performance rates or state CO_2 emission goals are not met.

1. Compliance periods, monitoring and reporting requirements for affected EGUs

For plans that include emission standards on affected EGUs, the EGU emission standards for the interim period must have schedules of compliance for each interim step 1, 2 and 3 for the calendar years 2022-2024, 2025-2027 and 2028-2029, respectively. For the final period, EGUs must have emission standards that have schedules of compliance for each 2 calendar years starting in 2030 (i.e., 2030-2031, 2032-2033, 2034-2035, etc.). If a backstop is triggered for a state measures plan, the schedule of compliance for the federally enforceable emission standards must begin no later than 18 months after the backstop is triggered and end at the end of the same compliance period. For example, if a backstop is triggered on July 1, 2025, the compliance period for the backstop emission standards must begin no later than January 1, 2027, and end on December 31, 2027. The next compliance period for the backstop emission standards would be January 1, 2028-December 31, 2029.

In the June 2014 proposal, the EPA proposed that the appropriate averaging time for any rate-based emission standard for affected EGUs be no longer than 12 months within a plan performance period and no longer than 3 years for a mass-based standard. The EPA solicited comments on longer and shorter averaging times for emission standards included in state plans. The EPA received comments stating that the proposed 12 month averaging was too short and that there was no reason why the compliance period under a rate-based plan should be different from a mass-based plan. Comments stated that a multi-year averaging period is appropriate for rate-based and mass-based plans to account for variations that can occur in a single year, allowing operators the flexibility they need to manage unforeseen events. The commenters also recommended that the final rule use discrete 3-year periods for compliance reconciliation instead of the rolling-average approach proposed.

The EPA has considered all comments received on this matter and is finalizing the compliance periods indicated above, which respond to the comments by applying to both rate- and mass-based programs, providing compliance periods longer than one year, and establishing block compliance periods rather than a rolling average approach. We agree with comments that longer averaging periods allow for operational and seasonal variability to even out and provide a basis for emissions reductions that are more realistic than short term averaging might otherwise demonstrate. The EPA finalizes that states can choose to set shorter compliance periods for their emission standards but no longer than the compliance periods the EPA is finalizing in this rulemaking. The EPA recognizes that the compliance periods provided for in this rulemaking are longer than those historically and typically specified in CAA rulemakings. As reflected in long-standing CAA precedent, "[t]he time over which [the compliance standards] extend should be as short term as possible and should generally not exceed one month." See e.g., June 13, 1989 "Guidance on Limiting Potential to Emit in New Source Permitting" and January 25, 1995 "Guidance on Enforceability Requirements for Limiting Potential to Emit through SIP and §112 Rules and General Permits." The EPA determined that the longer compliance periods provided for in this rulemaking are acceptable in the context of this specific rulemaking because of the unique characteristics of this rulemaking, including that CO_2 is long-lived in the atmosphere, and this rulemaking is focused on performance standards related to those long-term impacts. The distinction between these unique characteristics and the EPA's long-standing practice regarding compliance periods is bolstered by the EPA guidance on appropriate averaging periods for emission limitations in NAAQS implementation. For example, the EPA guidance has stated that in implementation of the ozone standards, which have a short averaging period, the averaging period for VOC emission limitations should be correspondingly short. See 51 FR 43857. A longer averaging period for VOC emission limitations can allow spikes in emissions that adversely impact ambient air and violate the short term ozone standards. This is precisely the opposite of the unique characteristics cited above: the long-lived persistence of CO_2 in the stratosphere and the intent of these guidelines to address the long-term impacts.

State plans must contain requirements for tracking and reporting actual plan performance during implementation, which includes reporting of CO_2 emissions from affected EGUs. Affected EGUs must comply with emissions monitoring and reporting requirements that are largely incorporated from 40 CFR part 75 monitoring and reporting requirements. The majority of affected EGUs are already familiar with the reporting requirements of part 75, and because of this, the EPA has chosen to streamline the applicable reporting requirements for sources under the state plans in the final rule. States must require all affected EGUs to monitor and report hourly CO_2 emissions and net energy output (including total net MWh output that is comprised of generation, and where applicable, useful thermal output converted to net MWhs) to the EPA on a quarterly basis in accordance with 40 CFR part 75. Note that this requirement applies for all types of state plans, regardless of whether the state chooses the option of the CO_2 emission performance rates, a state rate-based CO_2 emission goal, or a state mass-based CO_2 emission goal.

In the June 2014 proposal, the EPA proposed that state plans must include monitoring, reporting and recordkeeping requirements for useful energy output from affected EGUs. Multiple commenters questioned whether gross rather than net electrical production should be reported by affected EGUs and recommended that the EPA should utilize gross rather than net generation. Many commenters recommended electricity to be reported in the form used in the

111(b) rules for consistency between reporting requirements and simplification of calculation of emission limitations between new and old sources. Commenters also stated that to the extent the EPA seeks to provide guidance to states regarding its preferred monitoring and reporting procedures, the EPA should encourage states to avoid imposing additional monitoring and reporting burdens by taking advantage of the monitoring requirements that already exist to the greatest extent possible. For example, the commenters noted that the 40 CFR part 75 monitoring procedures used to comply with other programs, such as the Title IV Acid Rain Program, provide much of the data that would be needed to demonstrate compliance under the rule. Comments stated that the June 2014 proposal appeared to mandate a monitoring approach that would eliminate key flexibilities provided in the part 75 regulations, thus requiring utilities to maintain separate document collection and reporting procedures and potentially eliminating important alternative monitoring options intended to ensure representative, cost-effective monitoring approaches are available. The commenters asked the EPA to revise its proposal to make clear that the procedures established under part 75 will suffice or explain the need for any exceptions. Commenters indicated that the rule should require all affected EGUs to monitor CO_2 emissions and net hourly electric output under 40 CFR part 75, and report the data using the EPA's Emission Collection and Monitoring Plan System (ECMPS) assuring a more uniform monitoring and reporting process for all EGUs. The EPA believes that the final monitoring and reporting requirements (via ECMPS) address the issue of duplicative requirements and alleviate concern about lost flexibility raised by commenters.

2. Plan performance demonstrations

The state plan must include emission performance checks, and for state measures plans, periodic program implementation milestones. The state plan must provide for tracking of emission performance, and for measures to be implemented if the emission performance of affected EGUs in the state does not meet the applicable CO_2 emission performance rates or state CO_2 emission goal during a performance period.

As discussed previously in section VII, the agency is finalizing CO_2 emission performance rates or state-specific CO_2 emission goals that represent emission levels to be achieved by 2030 and emission levels to be achieved on average over the 2022-2029 interim period, and over three interim steps of 2022-2024, 2025-2027 and 2028-2029. The EPA recognizes the importance of ensuring that, during the 8-year interim period (2022-2029) for the interim performance rates or interim state goal, a state is making steady progress toward achieving the required level of emission performance. For both emission standards plans and state measures plans, the final rule requires periodic checks on overall emission performance leading to corrective measures or implementation of the backstop, if necessary, as described in section VIII.F.3 below. States must demonstrate that the interim steps were achieved, on average during the interim step periods, at the end of each interim step.

In 2032 and every 2 years thereafter, states must demonstrate that affected EGUs achieved the final performance rates or state goal on average during each 2-year reporting period (i.e., 2030-31, 2032-33, 2034-2035 etc.). The multi-year performance periods for measuring actual plan performance against the performance rates or state goals allow states some flexibility that accounts for seasonal operation of affected EGUs, and inclusion of RE and demand-side EE efforts.

For a rate-based plan, emission performance is an average CO_2 emission rate for affected EGUs representing cumulative CO_2 emissions for affected EGUs over the course of each reporting period divided by cumulative MWh energy output[70] from affected EGUs over the reporting period, with rate adjustments for qualifying measures, such as RE and demand-side EE measures. For a mass-based plan, emission performance is total tons of CO_2 emitted by affected EGUs over the reporting period.

For emission standards plans, as discussed in section VIII.D, the state must submit a report to the EPA of the emissions performance comparison for each reporting period no later than the July 1 following the end of each reporting period

[70] For EGUs that produce both electric energy output and other useful energy output, there would also be a credit for non-electric output, expressed in MWh.

(i.e., by July 1, 2025; July 1, 2028; July 1, 2030; July 1, 2032; and so on).

The EPA notes that for certain types of emission standards plans, with mass-based emission standards in the form of an emission budget trading program, achievement of a state's mass-based CO_2 goal (including interim step goals and final goal) will be assessed by the EPA based on compliance by affected EGUs with their emission standards under the program, rather than CO_2 emissions during a specific interim step period or final period. As discussed in section VIII.C.3.b.(2)(a), this approach is limited to plans with emission budget trading programs where compliance by affected EGUs with the emission standards will ensure that, on a cumulative basis, the state interim and final mass-based CO_2 goals are achieved.[71] This approach allows for CO_2 allowance banking across plan performance periods, including from the interim period to the final period. As a result, CO_2 emissions by affected EGUs could differ from the state mass-based CO_2 goal during an individual plan performance period, but on a cumulative basis CO_2 emissions from affected EGUs would not exceed what is allowable if the interim and final CO_2 goals are achieved.

Also as discussed in section VIII.D, states that choose a

[71] Emission budget trading programs in such plans establish CO_2 emission budgets equal to or less than the state mass CO_2 goal, as specified for the interim plan performance period (including specified levels in interim steps 1 through 3) and the final two-year plan performance periods.

state measures plan must submit an annual report no later than July 1 following the end of each calendar year in the interim period. This annual report must include the status of the implementation of programmatic milestones identified in the state plan submittal. The annual report that follows the end of each reporting period (i.e., 2022-2024, 2025-2027, and 2028-2029) must also include an emissions performance comparison for the reporting period, as described above for the emissions standards plan. Beginning with the final period of 2030 and onward, states using a state measures plan must submit a biannual report no later than July 1 following the end of each reporting period with an emission performance comparison for each reporting period, consistent with the reporting requirements for emission standards plans.

In the June 2014 proposal, the EPA proposed that a state report is due to the EPA no later than the July 1 following the end of each reporting period. The EPA requested comment on the appropriate frequency of reporting of the different proposed reporting elements, considering both the goals of minimizing unnecessary burdens on states and ensuring program effectiveness. In particular, the agency requested comment on whether full reports containing all of the elements should only be required every 2 years rather than annually and whether these reports should be submitted electronically, to streamline transmission.

The EPA mainly received adverse comments for requiring annual state reporting; commenters stated that this requirement was too burdensome for both states and the EPA. Commenters also requested that the EPA extend the due date of the annual report from July 1 to at least December 31. Commenters stated that because of the timing of current data collection~~,~~ and the need to leave time to organize and submit the reports, allowing only 6 months after the close of the year is problematic. Commenters asked that the EPA consider reducing the amount of data required if annual reporting was required.

Considering the comments received and the goals of minimizing unnecessary burdens on states and ensuring program effectiveness, the EPA has reduced the frequency of reporting of emissions data to every 3 years for the first two interim steps and every 2 years thereafter. However, the EPA is finalizing that state reports are due to the EPA no later than July 1 following the end of each reporting period. The EPA believes states can design their state plans to receive the data and information needed for these reports in a timely manner so that this requirement can be met. Furthermore, some of the state reporting requirements, such as reporting of EGU emissions, can be met through existing reporting mechanisms (ECMPS) and would not place additional burdens on states.

3. Consequences if actual emission performance does not meet the CO_2 emission performance rates or state CO_2 emission goal

The EPA recognizes that, under certain scenarios, an approved state plan might fail to achieve a level of emission performance that meets the emission guidelines or the level of performance established in a state plan for an interim milestone. Despite successful implementation of certain types of plans, emissions under the plan could turn out to be higher than projected at the time of plan approval because actual conditions vary from assumptions used when projecting emission performance. Emissions also could theoretically exceed projections because affected entities under a state plan did not fulfill their responsibilities, or because the state did not fulfill its responsibilities.

The final rule specifies the consequences in the event that actual emission performance under a state plan does not meet, or is not on track to meet, the applicable interim and interim step CO_2 emission performance rates or state goals in 2022-2029, or does not meet the applicable final CO_2 emission performance rates or state CO_2 emission goal in 2030-2031 or later. For emission standards plans, the final rule specifies that corrective measures must be enacted once triggered.[72] The determination that

[72] As in the proposal preamble, the EPA continues to note that some types of plans are "self-correcting" in that they inherently would assure interim performance and full achievement of the state plan's required level of emission performance through requirements that are enforceable against affected EGUs. One example is a state plan with a rate-based emission performance level that requires affected EGUs collectively to meet an emission rate consistent with the state's required emission performance level, and allows EGUs to comply through an emission trading program. Such plans presumably would not trigger or require corrective measures.

a state is not on track to meet the applicable interim goal or interim step goals in 2022-2029 or the applicable final goal in 2030-2031 or later, or the CO_2 emission performance rates, will be made through the actual performance checks to be included in state reports of performance data described in section VIII.D.2.a above.

For states using the emission standard approach, if actual CO_2 emission performance by affected EGUs exceeds the specified level of emission performance in the state plan by 10 percent or more during any of the specified interim step reporting periods or during a final plan reporting period (after 2030), the state report must include a notification to the EPA that corrective measures have been triggered. If, in the event of such an exceedance, the EPA determines that corrective measures have been triggered and the state has failed to notify the EPA, the EPA will inform the affected EGUs that corrective measures have been triggered.

After an exceedance by 10 percent or more, the state must submit to the EPA a plan revision including corrective measures that adjust requirements or add new measures. The corrective measures must both ensure future achievement of the CO_2 emission performance rates or state CO_2 emission goal and achieve additional emission reductions to offset any emission performance deficiency that occurred during a performance period. The state must submit the revised plan to the EPA within 24 months after submitting the state report indicating the exceedance. The EPA will then act on the plan revision within 12 months, consistent with other plan revisions and with the timing for final plan submittals originally submitted by states.

For states using the state measures approach, the EPA is finalizing the backstop requirement as described in section VIII.C.4.b of this preamble. As discussed in section VIII.D.2, the determination that a state using the state measures approach is not on track to meet the applicable interim goal or interim step goals in 2022-2029 or the applicable final goal in 2030-2031 or later, or the CO_2 emission performance rates, is based on checks that must be included in state reports that must be submitted annually during the interim period and biannually during the final period. The state must report any failure to meet programmatic milestones during the interim period. In addition, the state must report actual performance checks, similar to the requirements discussed above for emission standards plans. If, at the time of the state report to the EPA, the state did not meet the programmatic milestones for the reporting period, or the performance check shows that actual CO_2 emission performance by affected EGUs exceeds the specified level of emission performance in the state plan submittal by 10 percent or more, the state must include in the state report a notification to the EPA that the backstop has been triggered. If, in the event of such an exceedance, the EPA determines that the backstop has been triggered and the state has failed to notify the EPA, the EPA will inform the affected EGUs that the backstop has been triggered.

Multiple commenters requested that corrective measures not be required in the case of a catastrophic, uncontrollable event. We recognize the possibility that an un-anticipatable system emergency could cause a severe stress on the electricity system for a length of time such that the multi-year requirements in a state plan may not be achievable by given EGUs without posing an otherwise unmanageable risk to reliability. We are finalizing a reliability safety valve that will allow a state to modify the emission standards for such EGUs for a maximum of 90 days. The reliability safety valve will allow such EGUs to operate under the modified emission standards rather than the emission standards specified in the relevant state plan for that time period (including an exceedance that would otherwise trigger corrective measures under an emission standard plan type or an exceedance that would trigger a backstop under a state measures plan type), while still requiring the CO_2 emission performance rates or the state CO_2 emission goal to be met. While use of the reliability safety valve would preclude an applicable event from triggering corrective measures or a backstop during the safety valve period, the state must still make up for any emission reductions that were lost during the safety valve period. See section VIII.H.2.e of this preamble.

Multiple commenters supported the inclusion of strong enforcement measures for ensuring the interim and final goals are met, including the required use of corrective measures when triggered. Other commenters provided feedback as to the percentage that actual emission performance would need to exceed the level of emission performance specified in the statewide plan to trigger corrective measures. Some commenters supported the proposed trigger (actual emission performance that is not within 10 percent of the projected performance) that we are finalizing, while some recommended a lower trigger and others recommended a trigger higher than 10 percent exceedance. We have decided to finalize the trigger at 10 percent exceedance because we view 10 percent as both low enough to ensure that states that need corrective measures implement them before they exceed their specified level of emission performance to a degree that might be irreversible, and high enough that corrective measures are not triggered by fluctuations in emissions that do not indicate that a state may not be able to achieve its projected goal.

The EPA requested comment on whether the agency should promulgate a mechanism under CAA section 111(d) similar to the SIP call mechanism in CAA section 110. Under this approach, after the agency makes a finding of the plan's failure to achieve the CO_2 emission performance rates or state CO_2 emission goal during a performance period, the EPA would require the state to cure the deficiency with a new plan within a specified period of time. If the state still lacked an approved plan by the end of that time period, the EPA would have the authority to promulgate a federal plan under CAA section 111(d)(2)(A). 79 FR 34830, 34908/1-2 (June 18, 2014).

The EPA intends that planned revisions to the part 60 implementing regulations will clarify (among other things) whether the EPA has authority to call for plan revisions under section 111(d) when a state's plan is not complying with the requirements of this guideline, and if so, precisely what procedures should apply. The EPA plans to propose these revisions to the 111(d) implementing regulations in the forthcoming notice of proposed rulemaking for the federal plan. The EPA is not taking final action now on this issue or the related change to the implementing regulations.

a. <u>Legal basis for corrective measures</u>. The EPA discussed the concept of corrective measures in our 1992 General Preamble for the Implementation of Title I of the CAA Amendments of 1990. 57 FR 13498 (Apr. 16, 1992). The General Preamble sets out four general principles that apply to all SIPs, "including those involving emissions trading, marketable permits and allowances." *Id.* at 13568. The fourth principle, accountability, means (among other things) that "the SIP must contain means … to track emission changes at sources and provide for corrective action if emissions reductions are not achieved according to the plan." In the General Preamble, we noted that Part D of Title I explicitly provided for this in certain instances by requiring milestones and contingency measures.

Some commenters noted that the contingency measures explicitly required by part D are required to be adopted in the attainment plan and ready to implement when a milestone is not achieved or the area fails to attain the relevant NAAQS. These commenters therefore concluded that corrective measures for 111(d) plans should likewise already be adopted in the 111(d) plan and ready to implement. We disagree. Under Part D, contingency measures are not expected to fully bring the area into attainment. In fact, this would not be possible given the difficulty of predicting in advance exactly what measures would be needed to fully attain. A better analogue in Part D for the corrective measures in these guidelines is the primary way Part D addresses failure to attain: the state is required to revise its plan in various ways within a certain time in order to bring about attainment. See, e.g., section 179(d). This is analogous to what we are requiring for corrective measures. Thus, part D contingency measures are unlike the corrective measures in this rule.

However, the requirement to revise an attainment plan in response to failure to attain differs from the corrective measures in these guidelines in one important respect. Under these guidelines, the corrective measures must make up the difference by which the plan fell short of the goal. There is no corresponding requirement in attainment planning to increase the stringency of the plan by an amount that somehow matches an amount by which the area failed to attain; instead the revised plan must demonstrate attainment, and other more stringent requirements (such as requirements for best available control measures) may be triggered.

This distinction is the natural result of the difference between these guidelines and NAAQS attainment planning. In this case, we are finalizing guidelines representing technology-based standards for a pollutant with cumulative and long-lasting effects. If a plan falls short of a performance goal, then in effect the standards of performance in the plan have failed to reflect the BSER over the corresponding period. Due to the cumulative effects of CO_2, it is possible to remedy this failure by requiring the plan to be revised in such a way that the standards of performance in the revised plan will reflect the BSER over the cumulative plan period, and this can be done by requiring the revised plan to make up the shortfall from the previous period. In short, the flexibility that these guidelines provide should not come at the cost of allowing the standards of performance to reflect less than the BSER over the long run.[73]

Some commenters noted that 111(d) does not contain explicit provisions regarding corrective measures, and they therefore inferred that the EPA is not authorized to require them. That

[73] Similar considerations apply to the requirement under the state measures approach to revise the plan to make up the shortfall.

inference is mistaken. The requirement for 111(d) plans to "provide for implementation and enforcement" of the standards of performance is ambiguous and does not directly speak to whether corrective measures should or should not be required. There is therefore a gap for the EPA to fill. While the discussion above about Part D does not independently provide any authority to fill this gap, the fact that Congress created a scheme with stages of planning in Part D suggests that it would be reasonable, if appropriate, to fill this gap in 111(d) in a similar way.

In this guideline, it is appropriate for certain types of emission standards plans to fill this gap with corrective measures. There are two ways an emission standards plan can provide for implementation of standards of performance that achieve the CO_2 emission performance rates or requisite state CO_2 emission performance goal. First, the state can set emission standards that necessarily achieve the performance rates or goal, even if the affected EGUs in the future vary in their relative amounts of electricity generated. Second, the state can set emission standards that are demonstrated to achieve the performance rates or goal based on assumptions about the relative amounts of electricity generated, but which may turn out to not actually achieve the goal. This is analogous to an attainment plan that demonstrated attainment by the applicable attainment date, but due to unpredicted economic changes actually failed to attain. In this second case, the EPA interprets the ambiguous language “provide for implementation . . . of standards of performance” in the context of achieving the performance rate or emissions goal, to mean that at the time the plan is submitted it must contain some mechanism to check the progress of the plan and correct course. The EPA has determined that, for this particular rule, the minimum mechanism is the set of milestones and provisions for corrective measures specified in this rule.

4. Out-year requirements: Maintaining or improving the level of emission performance required by the emission guidelines

The agency is determining CO_2 emission performance rates and state CO_2 emission goals for affected EGU emission performance based on application of the BSER during specified time periods. This raises the question of whether affected EGU emission performance should be maintained at the 2030 level – or instead should be further improved - once the final CO_2 emission performance rate or state CO_2 emission goal is met in 2030. This involves questions of performance rate and goal-setting as well as questions about state planning. The EPA believes that Congress either intended the emission performance improvements required under CAA section 111(d) to be permanent or, through silence, authorized the EPA to reasonably require permanence. Other CAA section 111(d) emission guidelines set emission limits that do not expire. Therefore, the EPA is finalizing that the level of emission performance for affected EGUs represented by the final CO_2 emission performance rates or state CO_2 emission goal should continue to be maintained in the years after 2030.

As noted above, the state plan must demonstrate that plan measures are projected to achieve the final emission performance level by 2030. In addition, the state plan must identify requirements that continue to apply after 2030 and are likely to maintain affected EGU emission performance meeting the final goal. The state plan would be considered to provide for maintenance of emission performance consistent with the final goal if the plan measures used to demonstrate projected achievement of the final goal by 2030 will continue in force and not sunset. After implementation, the state is required to compare actual plan performance against the final goal on a 2-year average basis starting in 2030, and to implement corrective measures or a backstop if triggered.

In the proposal, the EPA noted that "CAA section 111(b)(1)(B) calls for the EPA, at least every eight years, to review and, if appropriate, revise federal standards of performance for new sources" in order to assure regular updating of performance standards as technical advances provide technologies that are cleaner or less costly. The proposal "requests comment on the implications of this concept, if any, for CAA section 111(d)." 79 FR 34830, 34908/3 (June 18, 2014).

We acknowledge the obligation to review section 111(b) standards as stated. The EPA is not finalizing any position with respect to any implications of this concept for section 111(d).

We are promulgating rules for section 111(d) state plans that will establish standards of performance for existing sources to which a section 111(b) standard of performance would apply if such sources were new sources, within the definition in section 111(a)(2) of "new source." It is not necessary to address at this time whether subsequent review and/or appropriate revision of the corresponding section 111(b) standard of performance have any implications for review and/or revision of this rule.

a. Legal basis for maintaining emission performance. In the proposal, the EPA proposed "that the level of emission performance for affected EGUs represented by the final goal should continue to be maintained." The EPA explained that "Congress either intended the emission performance improvements required under CAA section 111(d) to be permanent or, through silence, authorized the EPA to reasonably require permanence. Other CAA section 111(d) emission guidelines set emission limits to be met permanently." 79 FR 34830, 34908/2 (June 18, 2014). We also requested comment on whether "we should establish BSER-based state performance goals that extend further into the future (e.g. beyond the proposed planning period), and if so, what those levels of improved performance should be." *Id.* at 34908/3.

We received adverse comment on establishing BSER-based state performance goals beyond the proposed planning period. Commenters argued that we did not have a sufficient basis at this time to determine what those future goals should be. We agree and have decided not to establish such goals. We are finalizing, though, that the level of emission performance for affected EGUs represented by the final goal should continue to be maintained, for the reasons given in our proposal and quoted above.

The general structure of the CAA supports our interpretation. Section 111(d) plans establish standards of performance that reflect the BSER, a technology-based standard. Generally speaking, in the future technology will only improve, and correspondingly the CAA does not provide explicit processes to relax technology-based standards. In contrast, the provisions in Part D of title I that address attainment of health-based standards, the NAAQS, explicitly provide that once the NAAQS are attained, emission reduction measures may be relaxes so long as the NAAQS are maintained. The absence in section 111(d) of explicit provisions for future relaxation of emission reduction measures, as compared to Part D, supports our interpretation that the emission reductions continue to be on-going after the CO_2 emission performance rates or state CO_2 emission goals are achieved in 2030. This is consistent with our past practice for section 111(d) rules, which do not contain any provision that in the future removes or relaxes the promulgated guidelines. In light of the persistence of CO_2 as a pollutant and its long-term impacts, it is particularly critical in these guidelines to explicitly provide for continuing emission reductions.

G. Additional Considerations for State Plans

1. Consideration of a facility's "remaining useful life" and "other factors"

This section discusses the way in which the final emission guidelines address the CAA section 111(d)(1) provision requiring the Administrator, in promulgating 111(d) regulations, to "permit the State in applying a standard of performance to any particular source under a [111(d)] plan . . . to take into consideration, among other factors, the remaining useful life of the existing source to which such standard applies."

The final guidelines permit a state, in developing its state plan, to fully consider and take into account the remaining useful life of an affected EGU and other factors in establishing the requirements that apply to that EGU, as discussed further below. Therefore, consideration of facility-specific factors and in particular, remaining useful life, does not justify a state making further adjustments to the performance rates or aggregate emission goal that the guidelines define for affected EGUs in a state and that must be achieved by the state plan. Thus, these guidelines do not provide for states to make additional goal adjustments based on remaining useful life and other facility-specific factors because they can fully consider these factors in designing their plans.

a. Statutory and regulatory backdrop. This section describes the statutory and existing regulatory background concerning facility-specific considerations in implementation of section 111(d).

Section 111(d)(1)(A) requires states to submit a plan that "establishes standards of performance" for existing sources. Under section 111(d)(1)(B), the plan must also "provide for implementation and enforcement of such standards of performance." Finally, the last sentence of section 111(d)(1) provides: "Regulations of the Administrator under this paragraph shall permit the State in applying a standard of performance to any particular source under a plan submitted under this paragraph to take into consideration, among other factors, the remaining useful life of the existing source to which such standard applies."

The EPA's 1975 implementing regulations[74] addressed a number of facility-specific factors that might affect requirements for an existing source under section 111(d). Those regulations provide that for designated pollutants, standards of performance in state plans must be as stringent as the EPA's emission guidelines. Deviation from the standard might be appropriate where the state demonstrates with respect to a specific facility (or class of facilities):

> *(1) Unreasonable cost of control resulting from plant age, location, or basic process design;*
>
> *(2) Physical impossibility of installing necessary control equipment; or*
>
> *(3) Other factors specific to the facility (or class of facilities) that make application of a less stringent standard or final compliance time significantly more reasonable.*

[74] 40 FR 53340 (Nov. 17, 1975).

This provision was amended in 1995 (60 FR 65387, December 19, 1995), and is now prefaced with the language "Unless otherwise specified in the applicable subpart on a case-by-case basis for particular designated facilities or classes of facilities." 40 CFR 60.24(f).

b. <u>Our proposal regarding the implementing regulations</u>. Our proposal stated that the reference to "[u]nreasonable cost of control resulting from plant age" in 60.24(f) "implements" the statutory provision on remaining useful life. We also stated that the implementing regulations "provide the EPA's default structure for implementing the remaining useful life provision of CAA section 111(d)." We noted that the prefatory language "unless otherwise specified in the applicable subpart" gives the EPA discretion to alter the extent to which the implementing rules applied if appropriate for a particular source category and guidelines. We requested comment on our analysis of the existing implementing regulations and any implications for our regulatory text in respect to how these guidelines relate to those regulations.

Commenters noted, among other things, that the sentence concerning "remaining useful life" was added in the 1977 CAA Amendments and that therefore it could not be said that provisions from the 1975 implementing regulations "implement" the sentence. The EPA does not think as a general matter that it is necessarily impossible that a pre-statutory amendment rule could continue to serve as a reasonable implementation of a post-statutory amendment provision. However, we also think it is appropriate, as we suggested in the June 2014 proposal, to specify in the applicable subpart for these guidelines that the provisions in 60.24(f) should not apply to the class of facilities covered by these guidelines. As a result, regardless of whether the implementing regulations appropriately implement the "remaining useful life" provision in general, the relevant consideration is that, as we now explain, these particular guidelines "permit the State in applying a standard of performance to any particular source under a plan submitted under this paragraph to take into consideration, among other factors, the remaining useful life of the existing source to which such standard applies."

c. <u>How these emission guidelines permit states to consider remaining useful life and other facility-specific factors</u>. The EPA notes that, in general, the implementing regulation provisions for remaining useful life and other facility-specific factors are relevant for emission guidelines in which the EPA specifies a presumptive standard of performance that must be fully and directly implemented by each individual existing source within a specified source category. Such guidelines are similar to a CAA section 111(b) standard in their form. For example, the EPA emission guidelines for sulfuric acid plants, phosphate fertilizer plants, primary aluminum plants, and Kraft pulp plants specify emission limits for sources.[75] In the case of such emission guidelines, some individual sources, by virtue of their age or other unique circumstances, may warrant special accommodation.

In these final guidelines for state plans to limit CO_2 from affected EGUs, however, the agency does not specify presumptive performance rates for individual EGUs. Instead, these guidelines provide collective performance rates for two classes of affected EGUs (steam generating units and stationary combustion turbines), and give states the alternative of developing plans to achieve a state emission goal for the collective group of all affected EGUs in a state. Providing states with the ability to consider facility-specific factors such as remaining useful life in designing their state plans is one of the fundamental reasons that the EPA designed the final rule in this way. In addition, the significant revisions since proposal to address achievability concerns (e.g., moving the start date from 2020 to 2022, and other changes in interim and final state goals summarized in the

[75] See "Phosphate Fertilizer Plants; Final Guideline Document Availability," 42 Fed. Reg. 12022 (Mar. 1, 1977); "Standards of Performance for New Stationary Sources; Emission Guideline for Sulfuric Acid Mist," 42 Fed. Reg. 55796 (Oct. 18, 1977); "Kraft Pulp Mills, Notice of Availability of Final Guideline Document," 44 Fed. Reg. 29828 (May 22, 1979); "Primary Aluminum Plants; Availability of Final Guideline Document," 45 Fed. Reg. 26,294 (Apr. 17, 1980); "Standards of Performance for New Stationary Sources and Guidelines for Control of Existing Sources: Municipal Solid Waste Landfills, Final Rule," 61 Fed. Reg. 9905 (Mar. 12, 1996).

next section) will help to ensure that states in practice can consider remaining useful life and other facility-specific factors in setting EGU requirements. Of course, EGUs vary considerably in age, so remaining useful life is potentially relevant to regulation of some units and not others.

The guidelines capitalize on the inherent flexibility offered by aggregate EGU performance rates and by the state goals approach, allowing states flexibility on the form of the EGU standards that they include in CAA section 111(d) plans. A state could select a form of standards (e.g., marketable credits or permits, retirement of certain older facilities after their useful life, etc.) that avoids or diminishes concerns about facility-specific factors such as remaining useful life. Even if a state adopted the CO_2 emission performance rates for fossil fuel-fired electric utility steam generating units and stationary combustion turbines, though, the state could take remaining useful life into consideration by allowing affected EGUs to comply using ERCs. In effect, under a trading program with repeating compliance periods, a facility with a short remaining useful life has a total outlay that is proportionately smaller than a facility with a long remaining useful life, simply because the first facility would need to comply for fewer compliance periods and would need proportionately fewer ERCs than the second facility. Buying ERCs could avoid excessive up-front capital expenditures that might be unreasonable for a facility with a short remaining useful life, and would reduce the potential for stranded assets.

In addition to providing states with flexibility on the form of the standards of performance in their plans, the guidelines leave to each state the design of the specific requirements that fall on each affected EGU in applying those standards. To the extent that an emission standard that a state may wish to adopt for affected EGUs raises facility-specific issues, the state may make adjustments to a particular facility's requirements on facility-specific grounds, so long as any such adjustments are reflected (along with any necessary compensating emission reductions to meet the state goal) in the state's CAA section 111(d) plan submission.

Finally, we note that these guidelines permit states to use a rate or mass CO_2 emission goal, and that each of these pathways allow states multiple design choices. Under either pathway states can take into consideration remaining useful life and seek to avoid stranded assets.

d. Why remaining useful life and other facility-specific factors do not warrant adjustments in the guidelines' performance rates and state goals. Under the final guidelines, remaining useful life and other facility-specific considerations do not provide a basis for adjusting the CO_2 emission performance rates, or the state's rate-based or mass-based CO_2 emission goals, nor do they affect the state's obligation to develop and submit an approvable

CAA section 111(d) plan that adopts the CO_2 emission performance rates or achieves the goal by the applicable deadline. After considering public comments discussed below and in the response to comments document, the EPA has retained this aspect of the proposed rule for the reasons described below.

As noted above, the final guidelines provide aggregate emission goals for affected EGUs in each state, in addition to the CO_2 emission performance rates. The guidelines also reflect a number of changes from proposal to address concerns about achievability of proposed state goals that were raised in public comments, many of which were explicitly prompted by consideration of the remaining useful life issue. The result is to afford states with broad flexibility to design requirements for affected EGUs to achieve the CO_2 emission performance rates or state CO_2 emission goals in ways that avoid requiring major capital expenditures, or imposing unreasonable costs, on those affected EGUs that have a limited remaining useful life. State plans may use any combination of the emissions reduction methods represented by the building blocks, and may also choose to employ emission reduction methods that were not assumed in calculating state goals.

To be more specific, the EPA notes that a state is not required to achieve the same level of emission reductions with respect to any one building block as assumed in the EPA's BSER analysis. A state may use any combination of measures, including those not specifically factored into the BSER by the EPA. The EPA has estimated reasonable rather than maximum possible implementation levels for each building block in order to establish overall state goals that are achievable while allowing states to take advantage of the flexibility to pursue some building blocks more aggressively, and others less aggressively, than is reflected in the goal computations, according to each state's needs and preferences. The guidelines provide further flexibility by allowing state plans to use emission reduction methods not reflected in the BSER. A description of multiple emission reduction methods is provided in section VIII.G.

f. Response to key comments on remaining useful life. In response to the proposed rule, some commenters said that stringent and binding state goals do not, as a practical matter, provide states with the flexibility on EGU requirements that the EPA claimed at proposal, and take away states' ability to consider remaining useful life for individual units. Some said the EPA's presumption at proposal that the issue of remaining useful life would arise infrequently is inaccurate because the EPA focused on capital investments late in a plant's useful life and did not consider stranded assets from retirement of coal-fired generation before the end of its useful life, or from retirement of EGUs that recently installed pollution controls. Commenters provided multiple examples of individual power plants, including relatively new plants, which they asserted would be forced to shut down under the proposal. One commenter said that the EPA's Integrated Planning Model outputs for the proposal demonstrate that integrated operation of the four building blocks would result in retirement of sources before the end of their useful life. A number of commenters raised concerns that the proposed interim goal would cause plant retirements and stranded assets. A number of commenters also asserted that the proposal would cause retirement of EGUs that recently invested in pollution controls to comply with requirements such as MATS or Best Available Retrofit Technology requirements of the Regional Haze program.

The EPA shares the goal of avoiding stranded assets. Although nothing in section 111(d) explicitly bars a guideline that results in some facilities becoming uneconomic before the end of their useful lives, the EPA nonetheless has striven to design the guidelines so as to give states flexibility to develop plans that allow power companies to recover their investments in generation units.

In addition, the EPA is addressing the key comments above by making changes to state goals and its goal-setting methodology. These changes include:

- Starting the interim goal period in 2022 rather than 2020, allowing more gradual progress toward the final goal
- Revising the goal-setting formula and the state goals

themselves

- Updating analyses of achievable levels of improvement through the building blocks that together represent the BSER, while keeping them at reasonable, rather than maximum, levels
- Providing an explicit phase-in schedule for meeting the revised interim goals, while also allowing a state the option of choosing its own emission improvement trajectory

The final guidelines also contain changes to avoid certain inconsistencies between the goal-setting methodology and accounting of reductions under state plans (e.g., interstate effects of RE programs) that could have made state goals less achievable for some states.

Together, these changes help to ensure that the state goals established in the final guidelines are achievable considering cost, and that states can, as a practical matter, consider the toolbox of available emission reduction methods that the final guidelines allow and choose the best way to achieve their state goals.

Several commenters said that that the statute does not authorize the EPA to require other facilities to achieve greater reductions to compensate for a facility that warrants relief based on remaining useful life. One said that consideration of remaining useful life and other relevant factors is a one-way ratchet that provides relief to sources that cannot achieve the BSER, and that the EPA turns that approach on its head by prohibiting a state from providing such relief to a specific facility unless it can identify another facility to "punish" by requiring additional emissions reductions to offset that relief.

The EPA disagrees with these comments, many of which appear to be predicated on an approach not taken in this rule: requiring states to set presumptive standards for individual affected EGUs. The EPA is not establishing BSER for individual facilities, and then requiring better-than-BSER from some facilities to make up to worse-than-BSER performance that a state authorizes for other facilities because of a short remaining useful life. Rather, as previously noted, the guidelines set aggregate performance rates and state goals that represent the aggregate emission level of affected EGUs in each state based on estimates of the aggregate impact of applying the BSER. In estimating the amount of improvement achievable through each building block e.g., improvement in heat rate or amount of generation shift to lower-emitting EGUs), the EPA relies on estimating the average achievable level rather than attempting to estimate the level achievable by each and every affected EGU. Thus, the fact that an individual facility may be unable, for example, to achieve the average level of heat rate improvement assumed in goal-setting is consistent with the EPA's analysis, and does not undermine the

EPA's determination of state goals.

An additional reason that the EPA believes that consideration of remaining useful life and other facility-specific factors does not warrant adjustments to state goals is that the design of the guidelines does not mandate that states impose requirements that would call for substantial capital investments at affected EGUs late in their useful life. Of the building blocks considered by the EPA in developing state goals, only the first block, heat rate improvements, involves capital investments at the affected EGUs. The other building blocks – generation shifts among affected EGUs, and addition of new RE generating capacity – do not generally involve capital investments by the owner/operator at an affected EGU.

In the case of heat rate improvements at affected EGUs, states can choose whether to require a greater or lesser degree of heat rate improvement than the percentage improvement assumed in the EPA's BSER determination, either because of the remaining useful life of one or more EGUs, other source-specific factors that the state deemed appropriate to consider, or any other relevant reasons. The agency also notes that any capital expenditures would be much smaller than capital expenditures required for example, for purchase and installation of scrubbers to remove sulfur dioxide; a fleet-wide average cost for heat rate improvements based primarily on best practices at coal-fired generating units would not likely exceed $100/kW, compared with a typical SO_2 wet scrubber cost of $500/kw (costs vary with unit size).[76] In addition, the proposed guidelines allow states to regulate affected EGUs through flexible regulatory approaches that do not require affected EGUs to incur large capital costs (e.g., averaging and trading programs). Under the EPA's proposed approach - establishing state goals and providing states with flexibility in plan design – states have flexibility to make exactly the kind of judgments necessary to avoid requiring capital investments that would result in stranded assets.

Remaining useful life and other factors, because of their facility-specific nature, are potentially relevant as states determine requirements that are directly applicable to affected EGUs. If relief is due a particular facility, the state has an available toolbox of emission reduction methods that it can use to develop a section 111(d) plan that will achieve the CO_2 emission performance rates or state CO_2 emission goals on time. The EPA therefore concludes that the remaining useful life of affected EGUs, and the other facility-specific factors identified in the existing implementing regulations, should not be regarded as a basis for adjusting the CO_2 emission performance rates or a state CO_2 emission goal, and should not relieve a state of its

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[76] Heat rate improvement methods and related capital costs are discussed in the GHG Abatement Measures TSD; SO_2 scrubber capital costs are from the documentation for the EPA's IPM Base Case v5.13, Chapter 5, Table 5-3, available at http://www.epa.gov/airmarkets/documents/ipm/Chapter_5.pdf.

obligation to develop and submit an approvable plan that achieves that goal on time.

g. Legal issues regarding remaining useful life. Section 111(d)(1) requires the EPA in promulgating section 111(d) regulations to "permit the State in applying a standard of performance to any particular source under a plan submitted under this paragraph to take into consideration, among other factors, the remaining useful life of the existing source to which such standard applies." Here, we discuss the legal basis for determining that the emission guidelines are consistent with this statutory requirement.

First, the phrase "remaining useful life" also appears in the visibility provisions of section 169A. There, in determining best available retrofit technology (BART), the state (or the EPA) must take into consideration (among other factors) "the remaining useful life of the source." 42 USC 7491(g)(2); see also *id.* (g)(1) (reasonable progress). In the context of the visibility program, we have interpreted this provision to mean that the remaining useful life should be considered when calculating the annualized costs of retrofit controls. *See* 40 CFR Pt. 51, App. Y, IV.D.4.k.1. This annualized cost is then used to determine a cost effectiveness, in dollars per ton of pollutant removed on an annual basis. As a result, a technology with a large initial capital cost that might have a reasonable cost-effectiveness for a facility with a long remaining useful life would have a much higher and possibly unreasonable cost-effectiveness for a facility with a short remaining useful life.

However, section 111(d)(1) is different than section 169A(g)(2) and need not be interpreted in the same way. The requirement in section 169A(g)(2) is a mandatory duty to consider remaining useful life in determining BART. Section 111(d)(1), in contrast, merely requires that EPA emission guidelines permit states to take into account remaining useful life (among other factors), and section 111(d)(1) does not specify how the EPA must permit that. Furthermore, section 111(d)(1) does not suggest that states must be given carte blanche to consider remaining useful life in any way that can be imagined. Thus, there is a gap in the statute (just as there is in section 169A(g)(2)) for the EPA to fill by determining how states might consider remaining useful life. As detailed in section VIII.B.6, these guidelines permit states to take into account remaining useful life in a number of reasonable ways and thus the guidelines satisfy the statutory obligation.

Even if the EPA were to consider the provision in section 111(d)(1) in the same light as section 169A(g)(2), we would note (as discussed in detail in VIII.B.6 above) that (for example) a trading program under these section 111(d) guidelines only requires compliance on a periodic basis and does not require any initial capital expenditures. Thus, over the life of the facility, a facility with a short remaining useful life will need fewer total credits or allowances than an otherwise comparable facility with a long remaining useful life, but the annualized cost to the two facilities is the same. In other words, under a trading program remaining useful life of a source is automatically accounted for in the way it is accounted for under the visibility program.

Some commenters stated that the EPA's interpretation of remaining useful life is impermissible. These commenters claimed that states, if they wish to take into account remaining useful life at one affected EGU, must relax the stringency of the emission standard for that EGU. Then, the state would be compelled to increase the stringency of emission standards at other affected EGUs in order to achieve the state performance goal. According to these commenters, section 111(d) does not allow this outcome.

First, the commenters are mistaken in their premise. As discussed in section VIII.B.6 and in the example immediately above, states can impose the exact same emission standards on two affected EGUs and still take into account remaining useful life through the availability of trading. In other words, states need not relax an emission standard here and strengthen an emission standard there in order to take into account remaining useful life. Thus, these guidelines permit states to take into account remaining useful life without any of the effects commenters are concerned about.

Second, even if states decide to relax emission standards at one EGU, on the basis of remaining useful life or any other factor, nothing in the last sentence of section 111(d)(1) prohibits these guidelines from requiring the state plan to still meet the state performance goal. In fact, that sentence is completely silent on the issue. Thus, there is a gap in the statute to fill not only with respect to the ways in which remaining useful life can be considered, but the concomitant effects if a state chooses to consider remaining useful life in a particular way. In this case the concomitant effect of a state relaxing one emission standard may be that the state must make up for it elsewhere in order to meet the goal, but nothing in section 111(d)(1), including the statutory requirement to permit consideration of remaining useful life, prohibits that outcome.

2. Electric reliability

The final rule features overall flexibility, a long planning and implementation horizon, and the widest possible range of options for states and affected EGUs to achieve the CO_2 emissions goal. This design reflects, among other things, the EPA's commitment to ensuring that the final rule does not interfere with the industry's ability to maintain the reliability of the nation's electricity supply. Comments from state, regional and federal reliability entities, power companies and others, as well as consultation with the Department of Energy (DOE) and Federal Energy Regulatory Commission (FERC), helped inform a number of changes made in this final rule to address reliability. In addition, FERC conducted one national and three regional technical conferences on the proposed rulein which the EPA participated.

As discussed throughout the preamble and TSDs, the electricity sector is undergoing a period of intense change. While the change in the resource mix has accelerated in recent years, wind, solar, other RE, and EE resources have been reliably participating in the electric sector for a number of years. Many of the potential changes to the electric system that the final rule may encourage, such as shifts to cleaner sources of power and efforts to reduce electricity demand, are already well underway in the electric industry. To the extent that the final rule accelerates these changes, there are multiple features in the electricity system that ensure that electric system reliability will be maintained. Electric system reliability is continually being considered and planned for. For example, in the Energy Policy Act of 2005, Congress added a section to the Federal Power Act to make reliability standards mandatory and enforceable by FERC and the North American Electric Reliability Corporation (NERC), the Electric Reliability Organization which FERC designated and oversees. Along with its standards development work, NERC conducts annual reliability assessments via a 10-year forecast and winter and summer forecasts; audits owners, operators and users for preparedness; and educates and trains industry personnel. Numerous other entities such as FERC, DOE, state PUCs, ISOs/RTOs, and other planning authorities also consider the reliability of the electric system. There are also numerous remedies that are routinely employed when there is a specific local or regional reliability issue. These include transmission system upgrades, installation of new generating capacity, calling on demand response, and other demand-side actions.

Additionally, planning authorities and system operators constantly consider, plan for, and monitor the reliability of the electricity system with both a long-term and short-term perspective. Over the last century, the electric industry's efforts regarding electric system reliability have become multidimensional, comprehensive, and sophisticated. Under this approach, planning authorities plan the system to assure the availability of sufficient generation, transmission, and distribution capacity to meet system needs in a way that minimizes the likelihood of equipment failure.[77] Long-term system planning happens at both the local and regional levels with all segments of the electric system needing to operate together in an efficient and reliable manner. In the short-term, electric system operators operate the system within safe operating margins and work to restore the system quickly if a disruption occurs.[78]

[77] Casazza, J. and Delea, F., *Understanding Electric Power Systems: An Overview of the Technology, the Marketplace, and Government Regulations*, IEEE Press, at 160 (2010).
[78] *Id.*

Mandatory reliability standards apply to how the bulk electric system is planned and operated. For example, transmission operators and balancing authorities have to develop, maintain, and implement a set of plans to mitigate operating emergencies.[79]

As the electricity market changes and new challenges emerge, electric system regulators and industry participants make changes to how the electric system is designed and operated to respond to these challenges For example, expressing reliability and rate concerns about fuel assurance issues, FERC recently issued an order requiring ISOs/RTOs to report on the status of their efforts to address market and system performance associated with fuel assurance.[80] In February of 2015, Midcontinent Independent System Operator (MISO), California Independent System Operator Corporation (CAISO), New York Independent System Operator (NYISO), Southwest Power Pool (SPP), ISO New England (ISO-NE), and PJM Interconnection (PJM) each filed a report with FERC highlighting their efforts to respond to fuel assurance

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[79] NERC Reliability Standard EOP-001-2.1b – Emergency Operations Planning, available at http://www.nerc.net/standardsreports/standardssummary.aspx.

[80] *Centralized Capacity Markets in Regional Transmission Organizations and Independent System Operators*, 149 FERC ¶ 61,145 (2014). FERC generally defines fuel assurance as "generator access to sufficient fuel supplies and the firmness of generator fuel arrangements". *Id.* P 5.

[81] For example, ISO-NE and PJM each filed "pay-for-performance" proposals to address fuel assurance in their regions. FERC recently acted on ISO-NE market rule changes providing increased market incentives in capacity, energy, and ancillary services markets for generators to be available to meet their obligations during reserve shortages. *ISO New England Inc.*, 147 FERC ¶ 61,172 (2014). Additionally, FERC conditionally approved a PJM "pay-for-performance" proposal that creates a new capacity product to provide greater assurance of delivery of energy and reserves

concerns.[81] This is just one of many examples where electric system regulators and industry participants recognized a potential reliability issue and are proactively searching for solutions.

The EPA's approach in this final rule is consistent with our commitment to ensuring that the final rule does not interfere with the industry's ability to maintain the reliability of the nation's electricity supply. Many aspects of the final rule's design are intended to support system reliability, especially the long compliance period and the basic design that allows states flexibility to include a large variety of approaches and measures to achieve the environmental goals in a way that is tailored to each state's energy resources and policies. Many commenters have expressed concerns that the proposed rule could jeopardize electric system reliability. We note that the EPA has received similar comments in EPA rulemakings dating as far back as the 1970s. The EPA has always and continues to take electric system reliability comments seriously anddespite these reoccurring comments with regard to reliability, the electric industry has done an excellent job of maintaining reliability including when it has had to comply with environmental rules with much shorter compliance periods, higher costs, and much less flexibility than this final rule. Now, more than ever, the electric industry has

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during emergency conditions, establishing credits for superior performance and charges for poor performance. *PJM Interconnection, L.L.C.*, 151 FERC ¶ 61,208 (2015).

tools available to maintain reliability, including mandatory and enforceable reliability standards.[82]

As with numerous prior CAA regulations affecting the electric power sector, environmental requirements for this industry are accommodated within the existing extensive framework established by federal and state law to ensure that electricity production and delivery are balanced on an ongoing basis and planned sufficiently to ensure reliability and affordability into the future. In addition, changes that the EPA is making in this final rule respond directly to the comments and the suggestions that we received on reliability and provide further assurance that implementation of the final rule will not create reliability

[82]For example, then Executive Vice President-Markets and current President of PJM, an RTO with a substantial amount of coal-fired capacity and generation, Andrew Ott discussed the success of PJM's market design in assuring that PJM met and exceeded target reserve margins while MATS was being implemented. *See* Statement of Andrew Ott, PJM Executive Vice President-Markets, FERC Technical Conference on Centralized Capacity Markets in Regional Transmission Organizations and Independent System Operators, AD13-7-000, at 3, 7 (Sept. 25, 2013), *available at* http://www.ferc.gov/EventCalendar/EventDetails.aspx?ID=6944&CalType= &CalendarID=116&Date=09/25/2013&View=Listview. At the FERC national Clean Power Plan Technical Conference, Michael J. Kormos, PJM Executive Vice President-Operations, said that PJM's markets have proven, "resilient enough to respond to different policy initiatives. . . Whether it is the Sulfur Dioxide Trading Program of the 1990's, the MATS rule or individual state RPS initiatives, the markets have been able to send the appropriate price signals that produce competitive outcomes."*See* Michael J. Kormos, PJM Executive Vice President, Statement at FERC Technical Conference on EPA's Clean Power Plan, AD15-4-000, at 3 (Feb. 19, 2015), *available at* http://www.ferc.gov/CalendarFiles/20150213081650-Kormos,%20PJM.pdf.

concerns.

First, the final rule allows significant flexibility in how the applicable CO_2 emission performance rates or the statewide CO_2 goals are met. Given the differing characteristics of the electric grid within each state and region, there are many paths to meeting the final rule's requirements that can be taken while continuing to maintain a reliable electricity supply. As further described elsewhere in Section VIII, states can develop plans to meet the CO_2 emission performance rates or state CO_2 emission goals by choosing from a variety of state plan types and approaches that afford states and affected EGUs appropriate flexibility. EE and other non-BSER approaches can strengthen a state's ability to establish a plan to meet the CO_2 emission performance rates or state CO_2 emission goals by providing a considerable amount of headroom above the levels of the rates and goals. EE especially, because it reduces load, can provide assurance that reliability can and will be maintained. Additionally, the final rule offers opportunities for trading among affected EGUs within and between states, and other multi-state compliance approaches that will further support electric system reliability.

Second, the final rule provides sufficient time to ensure system reliability. The final rule retains the 2030 date for the final period, which commenters largely supported as reasonable and not a concern for reliability, and addresses one of the key issues that commenters pointed to as a reliability-related concern by both moving the start of the interim period from 2020 to 2022 and adjusting the interim goals to provide a less dramatic initial reduction requirement and a more gradual glide path to the final 2030 goals. Both FERC’s May 15, 2015 letter and the comment record made it clear that providing sufficient time for planning and implementation was essential to ensuring electric system reliability. The EPA has responded by provided additional time to allow for planning and implementation of the final rule requirements.

As a result of these changes, the states themselves will have a meaningful opportunity – which many commenters suggested the timing and stringency of the proposal failed to create despite our intent to do so – to determine the timing, cadence and sequence of actions needed for states and sources to meet final rule requirements while accommodating the ongoing activity needed to ensure system reliability. The final rule provides more than six years before reductions are required and an eight-year period from 2022 to 2029 to meet interim goals. Moreover, while the final rule requires each state to submit a plan by August 31, 2016, we recognize that some states may need more than one year to complete all of the actions needed for their final state plans, including consultation with reliability entities. Therefore, the EPA is allowing an optional two-phased submittal process for state plans. If the state needs additional time to submit a final plan, then the state may submit an initial plan by August 31, 2016, that documents the reasons that the state needs more time and includes commitments to concrete steps that will ensure that the state will submit a final plan by August 31, 2018.

Third, we are including in the final rule a requirement that each state demonstrate in its state plan submittal that it has considered reliability issues in developing its plan. This was suggested by a number of commenters, and we agree that it is a useful element to state plan development.Fourth, the final rule provides a mechanism for a state to seek a revision to its plan in order to address changes in circumstances that could have reliability impacts if not accommodated in the plan. The long compliance timeframe, with several interim steps, naturally provides opportunities for states, working with their utilities and reliability entities, to assess how implementation is proceeding, identify unforeseen changes that may warrant plan revisions, and work with the EPA to make necessary revisions.

Finally, in response to a variety of comments, we are providing a reliability safety mechanism that provides a path for a state to come to the EPA during an immediate unforeseen, emergency situation that threatens reliability to inform the EPA that an affected EGU or EGUs may need to temporarily comply with modified emission standards to respond to this kind of reliability concern.

We provide more details about these various elements of the final rule, as well as other features of the rule that support system reliability, below.

a. Summary of key comments. The EPA received a number of comments regarding the proposed rule and electric reliability. Many commenters provided specific, useful ideas regarding changes that could be made to the proposal to specifically address their reliability concerns. For example, many commenters state that allowing additional time to comply could help in meeting the final rule requirements while addressing their reliability concerns. Some commenters suggest that additional time would allow them to evaluate potential reliability impacts and system changes that need to be made to comply with final rule requirements while allowing affected EGUs time to meet interim CO_2 emissions goals. The EPA also received comment that market-based approaches have features that could help support reliability, and therefore we should encourage states to join or form regional market-based programs. Commenters also stated that the EPA should require states to consult with grid operators who would analyze the impact of state plans on reliability. A number of commenters also suggested that the EPA should include some sort of reliability safety valve in the final rule. We note that many participants at the FERC technical conferences on the proposed rule also discussed a reliability safety valve in great detail with many suggestions for how such a reliability mechanism could be designed. The EPA appreciates these and all the comments we received regarding the interaction of the proposal and electric reliability. We carefully considered all comments and incorporated many of the suggested changes in this final rule.

b. Final rule flexibility. In issuing this final rule, the EPA considered public comments on the potential interaction between the proposal and electric reliability. While we have made every effort to develop guidelines that would steer clear of potential reliability disruptions, a number of commenters argued that the possibility of an unanticipated reliability event cannot be entirely eliminated. Of course, even in the absence of these guidelines, the electric system will not completely avoid reliability issues. The EPA designed the final rule to ensure to the greatest extent possible that actions taken by states and affected EGUs to comply with the final rule do not increase potential reliability issues or complicate their resolution. In fact, to the extent that meeting final rule requirements results in the reduction of demand, upgrades in transmission efficiency and infrastructure, and investment in new, more efficient technologies, the outcome could be that the system is more robust and faces fewer risks to electric reliability.

However many commenters expressed concern that notwithstanding these flexibilities, the proposed plan development schedule may not leave sufficient time to conduct reliability planning between the development of state plans and the proposed start of the interim period in 2020. To address these concerns and to support a more effective reliability planning process, the EPA is moving the start of the interim period from 2020 to 2022 and adjusting the interim goals to provide a less dramatic initial reduction requirement and a more gradual glide path to the final 2030 goals. This gradual application of the BSER over the 2022-2029 interim period provides the state with substantial latitude in selecting its own emission reduction glide path over that period.[83] As noted above, the final rule also provides states with up to three years to adopt and submit their final state plans, and afterwards states can, if necessary, revise their plans before the beginning of the interim period. This timing gives system operators the opportunity to do what they have already been doing; looking ahead to forecast potential contingencies that pose reliability risks and identifying those actions needed to mitigate those risks. The final rule allows states to develop a pathway over the interim period that reflects their own circumstances, such as reflecting planned additions and changes in generation mix and potentially taking advantage of opportunities for trading of credits or allowances by affected EGUs within and between states. Because achievement of the emission rates or goals can be demonstrated over several years, state plans can accommodate situations where for example, it may take time to develop new generation, pipelines, or transmission

[83] Also, we separated the glide path into three steps, 2022-2024, 2025-2027, and 2028-2029, that is also achievable "on average" over the 8-year interim period.

while still providing many options for meeting the final rule requirements and planning for the reliability of the system.

c. Considering reliability during state plan development process. Under CAA section 111(d)(1)(B), state plans must provide for the implementation and enforcement of standards of performance for affected EGUs. The EPA is requiring that each state demonstrate as part of its state plan submission that it has considered reliability issues while developing its plan in order to ensure that standards of performance can be implemented and enforced. If system reliability is threatened, the ability of affected EGUs to meet the requirements of this final rule could be compromised if they are required to operate beyond the emission standards set in state plans in order to maintain the reliability of the electric grid. The requirement that states consider reliability as part of the development of state plans is designed to ensure that state plans are flexible enough to avoid this kind of potential conflict between maintaining reliability and implementing emission standards for affected EGUs.

A number of commenters, notably ISOs and RTOs, pointed out that planning and anticipation of change are among the essential ingredients of ensuring the ongoing reliability of the electricity system. To that end, they recommended that as states are developing state plans, their activity include the consideration of the reliability needs of the region in which affected EGUs operate and of the potential impact of actions to be taken in compliance with state plans. Therefore, we are requiring that each state demonstrate in its final state plan submittal that it has considered reliability issues in developing its plan. One particularly effective way in which a state can make this demonstration is by consulting with the relevant ISOs/RTOs or other planning authorities as they develop their plans and documenting this consultation process in their state plan submissions. If a state chooses to consider reliability through consultation with the ISO/RTO or other planning authority, the state should request that the planning authority review the state plan at least once during the plan development stage and provide its assessment of any reliability implications of the plan. While following the recommendations of the planning authority would not be mandatory, the state should document its consultation process, any response and recommendations from the planning authority, and the state's response to those recommendations in its state plan submittal to the EPA. This consultation is designed to inform how the state might adjust its plan for meeting the CO_2 reduction goal required under this guideline; the consultation is not a basis for relaxing that goal. While we consider this process to be an effective way for a state to demonstrate that it considered reliability in developing its state plan, a state may provide other comparable support for a demonstration that it has considered reliability during the state plan development process.[84] The EPA believes that this requirement to demonstrate consideration of reliability will provide an essential

[84] While the EPA is requiring that the states demonstrate that they have considered reliability in developing their plans, state plan submissions will not be evaluated substantively regarding reliability impacts.

reliability evaluation in the state plan development process. It should further help states avoid any conflicts between state plans and the maintenance of reliability during implementation of the state plan and associated emission standards.

d. State plan modifications. If, during the implementation of a state plan, a reliability issue cannot be addressed within the range of actions or mechanisms encompassed in an approved state plan, the state can submit a plan revision to the EPA to amend its plan. In such a circumstance, the state plan may need to be adjusted to enable affected EGUs to continue to meet final rule requirements without causing an otherwise unmanageable reliability threat. Whether or not these circumstances occur will depend in part upon how each state designs its state plan. States that design plans with a good deal of flexibility, such as market-based plans or multi-state plans, are less likely to face a potential conflict between state plan requirements and the maintenance of reliability. States that participate in multi-state programs will be better able to weather unexpected risks to reliability.

Events not anticipated at the time of the final plan submittal - such as the retirement of a large low or zero-emitting unit - may trigger the request for state plan revisions. It may also be the case that facility-specific emissions standards in a state plan are proving to be too inflexible to allow the plan to accommodate market or other changes in the power sector. In such instances, there should be a lead time between the announced retirement of the unit and the need to amend the state plan. Therefore, the state should be able to utilize the revisions process that the EPA provides.

The EPA will review a plan revision per the requirements of 40 CFR part 60. If the state's request for a state plan revision must be addressed promptly to assure a reliable supply of electricity, the state must document the risks to reliability that would be addressed by the plan revision by providing the EPA with a separate analysis of the reliability risk from the ISO/RTO or other planning authority. This analysis should be accompanied by a statement from the ISO/RTO or other planning/reliability authority that there are no practicable alternative resolutions to the reliability risk. In this case, the EPA will conduct an expedited review of the state plan revision.

e. Reliability safety valve. Many commenters expressed concerns that a serious, unforeseen event could occur during the final rule implementation period that would require a quick response by system operators and affected EGUs in order to maintain system reliability. It is highly unlikely that there would be a conflict between activities undertaken under an approved state plan and the maintenance of electric reliability, except in the case of a state plan that puts relatively inflexible requirements on specific plants. While some have pointed out severe weather or other short-term events as potentially conflicting with state plans, we note that most of those events are of short duration and would not require major adjustments to emission standards on affected EGUs or state plans. For example, during an event like the extreme cold experienced in periods of the winter of 2013-2014, affected EGUs may need to briefly run at a higher level to accommodate increased demand and/or short-term unavailability of other generators. However, because compliance can be demonstrated over 2-3 years, such a short-term event would not cause affected EGUs to be out of compliance with their applicable requirements. States can ensure that this is true by drafting plans that allow adequate compliance flexibility to accommodate such short-term events.

We recognize, however, that there are potential system emergencies that cannot be anticipated that could cause a severe stress on the electricity system for a length of time such that the multi-year requirements in a state plan may not be achievable by certain affected EGUs without posing an otherwise unmanageable risk to reliability. There could be extremely serious events, outside the control of affected EGUs, that occur that require an affected EGU, or EGUs, to temporarily operate under modified emission standards to respond to this kind of reliability concern. For example, 1) a catastrophic event such as a geomagnetic disturbance caused by solar flares damages critical or vulnerable equipment necessary for reliable grid operation and a higher emitting resource needs to operate at increased levels until an alternative solution can be found; or 2) a major storm floods and causes severe damage to a large NGCC plant in a city with limited access to transmission, necessitating that another much higher emitting plant is needed to operate until the NGCC plant is repaired; or 3) a serious act of sabotage damages an important substation and it will take time to work around the problem, and in the meantime a high emitting plant will need to run until transmission access is restored; or 4) a large nuclear unit must cease generating due to a substantial public safety issue and therefore causes other affected EGUs to run at higher levels in the short-term until a longer-term solution can be found. This is not an all-inclusive list, but it is illustrative of the kind of unforeseeable, emergency situation, caused by an extraordinary, unanticipated, potentially catastrophic event that, in the case of a state plan that imposes inflexible, obligations on individual EGUs (especially with short averaging times), may trigger the need for immediate, short-term relief from those facility-specific requirements. In such an instance, the final rule provides a process to ensure that system reliability will not be compromised.

Under such a circumstance, for states using the emissions standards plan type, the state must notify the EPA that it is necessary to modify the emission standards for an affected EGU or EGUs so that for a maximum of 90 days, the EGU or EGUs may operate at an emission standard that is above the emission standard specified in the relevant state plan but that the CO_2 emission performance rates or the state CO_2 emission goal will still be met. The EPA will consider this reliability safety valve to be an approved short-term modification to the state plan without needing to go through the full state plan revision process if the state provides proper notification to the EPA. However, the EPA reserves the right to review such notification, and in the event that the EPA finds such notification is improper, the EPA may disallow the short-term modification and affected EGUs must operate under the approved state plan emission standards. The notification to the EPA must be in writing and must include a full description of the reliability concern and why an unforeseen, emergency situation that threatens reliability requires the affected EGU (or EGUs) to operate under modified emission standards from those originally imposed on it by the state plan. The state must also describe in its notification to the EPA how it is coordinating or will coordinate with relevant planning authorities to alleviate the problem in an expedited manner. The state should also include a written concurrence from the relevant planning authority supporting the temporary modification request or an explanation of why this kind of concurrence cannot be provided. Additionally, if the relevant planning authority has conducted a system-wide or other analysis of the reliability concern, the state should include that information in its request.

It is important to note that in such an instance requiring a short-term modification to the state plan, the state and affected EGUS must continue monitoring and reporting their emissions and generation pursuant to requirements in this final rule and under the state plan. Additionally, a short-term modification to the state plan is specific to the emissions standards for the affected EGU(s) needing to operate in a way that ensures system reliability, but such a modification may not alter or abrogate the overall obligations under approved state plans for the requisite state goal or performance rates to be met by affected EGUs.

At the end of this period of 90 days or less, the state must notify the EPA as to whether the reliability concern has been addressed and that it is requiring the affected EGU, or EGUs, to meet the original emissions standards in the state plan approved prior to the short-term modification going forward. It must also notify the EPA as to how the CO_2 emission performance rates or state CO_2 emission goals will be met going forward and enumerate how it will make up for any emission reductions that were lost during the safety valve period. If there still is a serious, ongoing reliability issue, the state must provide to the EPA a notice that it will be submitting a state plan revision. At the end of this period of 90 days or less, the emission standards originally approved under the state plan must be back in effect for the affected EGUs.

The EPA intends for this reliability safety valve to be used only in exceptional cases and only once by a state during the final rule implementation period. As discussed earlier, we are providing states with the flexibility to design a program that is appropriate for its electricity needs. This flexibility means that a conflict between the requirements of the state plan and maintenance of reliability should be extremely rare. If, however, the state finds that problems remain after imposition of the reliability safety valve, the state must submit a revision to its state plan.

f. <u>Coordination with federal partners</u>. The EPA, DOE, and FERC have agreed to coordinate efforts to help ensure continued reliable electricity generation and transmission during the implementation of the final rule. The three agencies have developed a coordination strategy that reflects their joint understanding of how they will work together to monitor final rule implementation, share information, and resolve any difficulties that +may be encountered. This strategy is based on the successful working relationship that the three agencies established in their joint effort to work together to monitor reliability during MATS implementation.

3. Consideration of effects to employment and economic development

Labor markets respond in complex ways to state policies in a way that depends a wide range of factors (e.g., available local labor supply, broader labor market trends). Employment effects in a state will depend upon the particular steps that each state takes in their plan, as well as broader trends at the regional and national level. For most state plans, the precise effects will often be very hard to quantify because they will depend on choices made by utilities and others as the plans are implemented. The EPA's illustrative analysis highlights the likelihood for some additional job loss in sectors related to coal that are attributable to implementation of this rule. At the same time, the EPA's illustrative analysis highlights that there will be new jobs in the utility power sector associated with both improving the efficiency of fossil fuel-fired power plants and construction of new natural gas-fired and renewable power production, and new jobs in the RE and demand-side EE sectors. Consideration of these effects in the context of the particulars of the state plan can help states craft plans that, to the extent possible, meet multiple environmental and economic goals.

The Partnership for Opportunity and Workforce and Economic Revitalization (POWER) Initiative is a new interagency effort led by the Economic Development Administration in the Department of Commerce that specially targets economic development assistance to communities affected by changes in the coal industry and the utility power sector and may be of assistance to communities that experience job losses.[85] In addition, the Department of Commerce,

[85] http://www.eda.gov/power/.

Department of Labor (DOL), Small Business Administration, and the Appalachian Regional Commission have together created an initiative to issue grants to partnerships of regionally-driven economic development and workforce development organizations in impacted coal communities.[86]

4. Workforce considerations

Some stakeholders commented that, to ensure that emission reductions are realized, it is important that construction, operations and other skilled work undertaken pursuant to state plans is performed to specifications, and is effective, safe, and timely. The EPA agrees and encourages states to ask for a demonstration that the work is performed by a proficient workforce. A good way to ensure such a workforce is to require that workers have been certified by: 1) an apprenticeship program that is registered with the U.S. DOL, Office of Apprenticeship or a state apprenticeship program approved by the DOL; 2) a skill certification aligned with the U.S. DOE Better Building Workforce Guidelines and validated by a third party accrediting body recognized by DOE; or 3) other skill certification validated by a third party accrediting body.

5. Tenth Amendment legal considerations

Some commenters have raised concerns that the emission guidelines and requirements for 111(d) state plans violate

[86] https://www.whitehouse.gov/the-press-office/2015/03/27/fact-sheet-partnerships-opportunity-and-workforce-and-economic-revitaliz.

principles of federalism embodied in the U.S. Constitution, particularly the Tenth Amendment. These commenters claim that states will be unconstitutionally "coerced" or "commandeered" into taking certain actions in order to avoid the prospect of either a federal 111(d) plan applying to sources in the state, or of losing federal funds.

We disagree on both fronts. First, the prospect of a federal plan applying to sources in a state does not "coerce" or "commandeer" that state into submitting its own satisfactory plan. Far from violating principles of federalism, this rule provides states with the initial opportunity to submit a satisfactory state plan, and provides states flexibility in developing that plan. If a state declines to take advantage of that opportunity, affected EGUs in that state will instead be subject to a federal plan that satisfies statutory requirements.[87] This approach is consistent with ordinary cooperative federalism regimes that federal courts have routinely upheld against Tenth Amendment challenges.[88]

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[87] Among other things, a federal plan will implement standards of performance subject to specific statutory requirements. *See* 42 U.S.C. § 7411(a)(1). The APA and CAA would prohibit the imposition of any federal plan that is "arbitrary, capricious, an abuse of discretion, or otherwise not in accordance with law." 5 U.S.C. § 706(2)(a). Particularly given these independent constraints on the EPA's authority with respect to any potential federal plan, the prospect of any such plan would not commandeer states or coerce them into submitting their own state plans.

[88] *See, e.g., Hodel v. Va. Surface Mining & Reclamation Ass'n, Inc.*, 452 U.S. 264, 283-93 (1981); *Texas v. EPA*, 726 F.3d 180, 196-97 (D.C. Cir. 2013) (noting that "Supreme Court precedent repeatedly affirm[s] the constitutionality of federal statutes

Second, states that decline to take certain actions under this rule will not face the prospect of sanctions, such as withdrawn federal highway funds. CAA section 111 does not contain sanctions provisions, and we are finalizing revisions to these emission guidelines making explicit that the EPA will not withhold federal funds from a state on account of that state's failure to submit or implement an approvable 111(d) state plan.

Some commenters pointed to section 110(m) as a possible source of the EPA's sanction authority.[89] Section 110(m) grants the EPA discretionary authority to withhold some federal highway funds under certain conditions. However, section 110(m) requires the EPA to adopt regulations to "establish criteria for exercising" this discretionary authority, and the only EPA regulations implementing section 110(m) apply to SIPs submitted under section 110.[90]

The EPA never intended to even imply that we would contemplate using this authority to encourage state participation in this rule under section 111. To the contrary, we believe that imposition of a federal plan rather than sanctions is the appropriate path in the context of this program. Accordingly, regardless of whether the EPA could theoretically apply

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that allow States to administer federal programs but provide for direct federal administration if a State chooses not to administer it").

[89] Other commenters point to CAA section 179 as a possible direct source of this sanctions authority. However, the mandatory sanctions outlined in section 179 clearly apply only in the context of nonattainment SIPs. *See* 42 U.S.C. § 7509(a).

[90] 40 CFR 52.30 (defining "plan or plan item").

discretionary sanctions against states in the section 111(d) context, the rule today forbids the agency from exercising any such authority. We have included in this rule a provision that prohibits the agency from imposing sanctions in the event that a state fails to submit or implement a satisfactory plan under this rule. As states consider whether to take advantage of the opportunity to develop state plans, they can be assured that the EPA will not withdraw federal funding should they decline to participate.

H. Resources for States to Consider in Developing Plans

As part of the stakeholder outreach and comment processes, the EPA asked states what the agency could do to facilitate state plan development and implementation. In addition, after the comment period closed, the EPA continued to consult with state organizations including the Association of Air Pollution Control Agencies (AAPCA), Environmental Council of the States (ECOS), National Association of Clean Air Agencies (NACAA), National Association of Regulatory Utility Commissioners (NARUC), National Association of State Energy Officials (NASEO) and the National Governors Association (NGA).

Some states indicated that they wanted the EPA to create resources to assist with state plan development, especially resources related to accounting for RE and demand-side EE in state plans. They requested clear methodologies for estimating emission reductions from RE and demand-side EE policies and programs so that these could be included as part of their compliance strategies. Stakeholders said that these tools and metrics should build upon the EPA's "Roadmap for Incorporating Energy Efficiency/Renewable Energy Policies and Programs into State and Tribal Implementation Plans," as well as the State Energy Efficiency Action Network's "Energy Efficiency Program Impact Evaluation Guide." In addition, stakeholders requested clear guidance on how to measure the impacts of RE and demand-side EE programs using established EM&V protocols.

The EPA also heard that states would like guidance on plan development to be released at the same time as this final rule. This guidance should include allowable programs and policies for compliance, examples of compliance pathways, clear information on multi-state plan development, and identification of tools.

As a result of this feedback, in consultation with U.S. DOE and other federal agencies, the EPA continued to refine its toolbox of decision support resources at: http://www2.epa.gov/www2.epa.gov/cleanpowerplantoolbox. The site includes information on regulatory requirements, including state plan guidance and state plan decision support. The state plan guidance section serves as a central repository for the final emission guidelines, RIA, guidance documents, TSDs and other supporting materials. The state plan decision support section includes information to help states evaluate different approaches and measures they might consider as they initiate plan development. This section includes, for example, a summary of existing state climate and RE and demand-side EE policies and programs, information on electric utility actions that reduce CO_2, and tools and information to estimate the emissions impact of RE and demand-side EE programs.

The EPA notes that our inclusion of a measure in the toolbox does not mean that a state plan must include that measure. In fact, inclusion of measures provided at the website does not necessarily imply the approvability of an approach or method for use in a state plan. States will need to demonstrate that any measure included in a state plan meets all relevant criteria and adequately addresses elements of the plan components discussed in section VIII.D of this preamble.

I. Considerations for State Plans that Include CO_2 Emission Reduction Measures that Occur at Affected EGUs

Multiple actions may be taken at affected EGUs that reduce CO_2 emissions from an affected EGU and/or improve its CO_2 emission rate. This section describes this range of emission reduction actions and their accounting treatment in a state plan. Some of these actions do not necessitate additional accounting, monitoring or reporting requirements. Such actions are discussed in section VIII.I.1 below, and include heat rate improvements, fuel switching from one fossil fuel to another, integration of RE into EGU operations, and CHP expansion or retrofit. Other actions, however, do necessitate additional accounting, monitoring, or reporting requirements. These include use of CCS, CCU and biomass, as discussed in section VIII.I.2 below.

1. Actions without additional accounting and reporting requirements

Many actions will reduce the reported CO_2 emissions or CO_2 emission rate of an affected EGU, without the need for additional accounting or monitoring and reporting requirements beyond the required CEMS tracking of actual stack CO_2 emissions and tracking of actual energy output.[91] The effect of these actions will result in changes in reported CO_2 emissions and/or energy output by an affected EGU. These actions include:

- heat rate improvements;
- fuel switching to a fossil fuel with lower carbon content (e.g., from coal to natural gas);
- integrated RE;[92] and
- CHP, including retrofit of an affected EGU to a CHP configuration, or revising the useful energy outputs (electrical and thermal) at an affected EGU already operating in a CHP configuration.[93]

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[91] Monitoring and reporting requirements for affected EGU CO_2 emissions and useful energy output are addressed in section VIII.F.

[92] "Integrated RE" refers to RE that is directly incorporated into the mechanical systems and operation of the EGU. An example is a solar thermal energy system used to preheat boiler feedwater. Such approaches reduce the amount of fossil fuel heat input per unit of useful energy output.

[93] The emission reduction potential from CHP stems from the unit using less fuel for producing useful electrical and thermal outputs than would be required to run separate electrical and thermal units. The emission reduction would depend on the type of

Heat rate improvements, fuel switching, integrating RE and CHP would not require any additional accounting or monitoring and reporting, because under the emission guidelines affected EGUs are already required to monitor and report CO_2 emissions at the stack level, and, for rate-based plans, to monitor and report useful energy output. Stack monitoring would reflect reductions in CO_2 emissions from efficiency improvements, changes in fuel use (including incorporation of RE), and other on-site changes.

2. Actions with additional accounting and reporting requirements

Certain actions that may be taken at an affected EGU to reduce CO_2 emissions, specifically application of CCS and CCU, and use of biomass, require additional accounting and reporting.

a. Application of CCS. Affected EGUs may utilize retrofit CCS technology to reduce reported stack CO_2 emissions from the EGU.[94] Affected EGUs that apply CCS under a state plan must meet the same monitoring, recordkeeping and reporting requirements for sequestered CO_2 as new units that implement CCS to meet final standards of performance under CAA section 111(b) for new EGUs.[95]

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affected EGU and available steam hosts in the vicinity of the affected EGU. A conventional combustion turbine generator, for example, converted into a CHP unit could effectively result in a reduction of 25 percent or more in the reported CO_2 emission rate. The potential retrofitted EGU CHP market consists of converted simple cycle turbines, older steam plants in urban areas, and combined cycle units near beneficial thermal loads.

[94] Addition of retrofit CCS technology should not trigger CAA section 111(b) applicability for modified or reconstructed sources. Pollution control projects do not trigger NSPS modifications and addition of CCS technology does not count toward the capital costs of reconstruction.

[95] Standards of Performance for Greenhouse Gas Emissions from New, Modified, and Reconstructed Stationary Sources: Electric

Specifically, the final CAA section 111(b) rule for new sources requires that, if a new affected EGU uses CCS to meet the applicable CO_2 emission limit, the EGU must report in accordance with 40 CFR part 98 subpart PP (Suppliers of Carbon Dioxide), and the captured CO_2 must be injected at a facility or facilities that report in accordance with 40 CFR part 98 subpart RR (Geologic Sequestration of Carbon Dioxide).[96,97] See 40 CFR part 60.46Da(h)(5) and part 60.5555(d). Taken together, these requirements ensure that the amount of captured and sequestered CO_2 will be tracked as appropriate at project- and national-levels, and that the status of the CO_2 in its sequestration site will be monitored, including air-side monitoring and reporting. As detailed in the preamble for the CAA section 111(b) standards for new EGUs, the EPA is convinced that there is ample evidence that CCS is technically feasible and that partial CCS can be implemented at a new fossil fuel-fired steam generating EGU at a

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Utility Generating Units.

[96] The final CAA section 111(b) rule finalizes amendments to subpart PP reporting requirements, specifically requiring that the following pieces of information be reported: (1) the electronic GHG Reporting Tool identification (e-GGRT ID) of the EGU facility from which CO_2 was captured, and (2) the e-GGRT ID(s) for, and mass of CO_2 transferred to, each GS site reporting under subpart RR. As noted, the final 111(b) rule also requires that any affected EGU unit that captures CO_2 to meet the applicable emissions limit must transfer the captured CO_2 to a facility that reports under 40 CFR part 98 subpart RR.

[97] Under final requirements in the CAA 111(b) NSPS, any well receiving CO_2 captured from an affected source, be it a Class VI or Class II well, must report under subpart RR. A UIC Class II well’s regulatory status does not change because it receives such CO_2, nor does it change by virtue of reporting under subpart RR.

cost that is reasonable and that is consistent with the cost of other dispatchable, non-NGCC generating options. In the June 2014 proposal, the EPA noted that CCS technology at existing EGUs would entail additional considerations beyond those at issue for newly constructed EGUs. Specifically, the cost of integrating a retrofit CCS system into an existing facility may be expected to be substantial, and some existing EGUs may have space limitations and thus may not be able to accommodate the expansion needed to install the equipment to implement CCS. Further, the EPA noted that aggregated costs of applying CCS as a component of the BSER for the large number of existing fossil fuel-fired steam EGUs would be substantial and would be expected to affect the cost and potentially the supply of electricity on a national basis. For those reasons the EPA did not propose nor finalize CCS as a component of the BSER for existing EGUs.

However, the EPA noted that CCS may be a viable CO_2 mitigation technology at some existing sources and that it would be available to states and to sources as a compliance option. Numerous commenters agreed with the EPA's proposed determination that CCS technology is not part of the BSER building blocks for existing EGUs. Other commenters opposed inclusion of CCS requirements in state plans and provided specific reasons why CCS would not be applicable in certain states. Many commenters felt that CCS technology is not adequately demonstrated and is not economically practical at this time. Other commenters argued that

CCS is an available technology and that it can be implemented at more EGUs than predicted by EPA modelling.

Some commenters noted that there are opportunities to reduce the cost of CCS implementation by selling the captured CO_2 for use in Enhanced Oil Recovery (EOR) operations. One commenter expressed concern that federal requirements under the Greenhouse Gas Reporting Program – specifically the requirement (mentioned above) to report under 40 CFR part 98 subpart RR – would foreclose, rather than encourage, the use of captured CO_2 for EOR. The EPA received similar public comments on the CAA 111(b) proposal for new EGUs. The EPA disagrees with the commenters' assertions and addressed those in the preamble for the final standards of performance and in the Response-to-Comments (RTC) document for the CAA 111(b) NSPS rulemaking. The EPA noted that the cost of compliance with subpart RR is not significant enough to offset the potential revenue for the EOR operator from the sale of produced oil for CCS projects that are reliant on EOR. The costs associated with subpart RR are relatively modest, especially in comparison with revenues from an EOR field.

b. Application of CCU. The EPA received comments suggesting that carbon capture and utilization (CCU) technologies should also be allowed as a CO_2 emission rate adjustment measure for affected EGUs.

Potential alternatives to storing CO_2 in geologic formations are emerging and these relatively new potential alternatives may offer the opportunity to offset the cost of CO_2 capture. For example, captured anthropogenic CO_2 may be stored in solid carbonate materials such as precipitated calcium carbonate (PCC) or magnesium or calcium carbonate, bauxite residue carbonation, and certain types of cement through mineralization. The carbonate materials produced can be tailored to optimize performance in specific industrial and commercial applications. For example, these carbonate materials have been used in the construction industry and, more recently and innovatively, in cement production processes to replace Portland cement.

The Skyonics Skymine® project, which opened its demonstration project in October 2014, is an example of captured CO_2 being used in the production of carbonate products. This plant converts CO_2 into commercial products. It captures over 75,000 tons of CO_2 annually from a San Antonio, Texas, cement plant and converts the CO_2 into other products including sodium carbonate and sodium bicarbonate.[98] Other companies – including Calera[99] and New Sky[100] – also offer commercially available technology for the beneficial use of captured CO_2. These processes can be utilized in a variety of industrial applications – including at fossil fuel-fired power plants.

However, consideration of how these emerging alternatives could be used to meet CO_2 emission performance rates or state CO_2

[98] http://skyonic.com/technologies/skymine.
[99] http://www.calera.com/beneficial-reuse-of-co2/process.html.
[100] http://www.newskyenergy.com/index.php/products/carboncycle.

emission goals would require a better understanding of the ultimate fate of the captured CO_2 and the degree to which the method permanently isolates the captured CO_2 or displaces other CO_2 emissions from the atmosphere.

Several commenters also suggested that algae-based CCU (i.e., the use of algae to convert captured CO_2 to useful products – especially biofuels) should be recognized for its potential to reduce emissions from existing fossil-fueled EGUs.

Unlike geologic sequestration, there are currently no uniform monitoring and reporting mechanisms to demonstrate that these alternative end uses of captured CO_2 result in overall reductions of CO_2 emissions to the atmosphere. As these alternative technologies are developed, the EPA is committed to work collaboratively with stakeholders to evaluate the efficacy of alternative utilization technologies, to address any regulatory hurdles, and to develop appropriate monitoring and reporting protocols to demonstrate CO_2 reductions.

In the meantime, state plans may allow affected EGUs to use qualifying CCU technologies to reduce CO_2 emissions that are subject to an emission standard, or those that are counted when demonstrating achievement of the CO_2 emission performance rates or a state rate-based or mass-based CO_2 emission. State plans must include analysis supporting how the proposed qualifying CCU technology results in CO_2 emission mitigation and provide monitoring, reporting, and verification requirements to demonstrate the reductions. The EPA would then review the appropriateness and basis for the analysis and the verification requirements in the course of its review of the state plan.

c. Biomass co-firing and repowering. Affected EGUs may use qualifying biomass in order to reduce CO_2 emissions that are subject to an emission standard requirement, or those that are counted when demonstrating achievement of the CO_2 emission performance rates or a state rate-based or mass-based CO_2 emission goal. Not all forms of biomass are expected to be approvable (see section below for considerations pertaining to biomass use in state plans). A state would propose qualifying biomass feedstocks or categories of biomass feedstocks in its plan and the proposed treatment of biogenic CO_2 emissions, including measures to ensure emission reduction benefits. State plans must include analysis supporting how proposed qualifying feedstocks or feedstock categories are considered appropriate as a CO_2 emission mitigation approach as well as the proposed treatment of biogenic CO_2 emissions (i.e., the proposed level of biogenic CO_2 emissions from use of the biomass feedstock that would not be counted when demonstrating compliance with an emission standard, or when demonstrating achievement of the CO_2 emission performance rates or a state rate-based or mass-based CO_2 emission goal) and quality control measures. The EPA would review the appropriateness and basis for such determinations and accounting measures in the course of its review of a state plan.

The EPA received multiple comments supporting the use of biomass feedstocks as a means of reducing CO_2 emissions within state plans. Several commenters also asserted that states should be able to determine how biomass can be used in their plans. Additionally, the EPA received a range of comments regarding the valuation of CO_2 emissions from biomass combustion. Some argued that all biomass feedstocks should be considered "carbon neutral," while others maintained that only the full stack emissions from biomass combustion should be counted. As discussed in the next section, the revised *Framework for Assessing Biogenic Carbon Dioxide for Stationary Sources*[101] and the 2012 Science Advisory Board peer review of the *2011 Draft Framework* find that it is not scientifically valid to assume that all biogenic feedstocks are "carbon neutral."[102] Other comments focused on the use of sustainably-derived agricultural and forest biomass feedstocks, including stakeholders who supported and those against such feedstocks as approvable elements, and those who wanted further definition of these feedstocks. As discussed above, states can propose qualifying biomass feedstocks or feedstock categories in state plans. The EPA will review the appropriateness and basis for determining qualifying biomass feedstocks or feedstock categories in its review of a state plan.

[101] www.epa.gov/climatechange/downloads/Framework-for-Assessing-Biogenic-CO2-Emissions.pdf.
[102] www.epa.gov/climatechange/ghgemissions/biogenic-emissions.html.

(1) Considerations for use of biomass in state plans. As detailed in the President's Climate Action Plan,[103] part of the strategy to address climate change includes efforts to protect and restore our forests, as well as other critical landscapes including grasslands and wetlands, in the face of a changing climate. This country's forests currently play a critical role in addressing carbon pollution, removing nearly 12 percent of total U.S. greenhouse gas emissions each year. Conservation and sustainable management can help ensure our forests and other lands will continue to remove carbon from the atmosphere while also improving soil and water quality, reducing wildfire risk and enhancing forests' resilience in the face of climate change.

The EPA recognizes that some biomass-derived fuels can play a role in CO_2 emissions reduction strategies. The EPA also anticipates that some states may consider biomass-derived fuels used in electricity generation as a way to reduce CO_2 emissions from affected EGUs, and will include them as part of their state plans to meet the emission guidelines.

With regard to assessing qualifying biomass specified in state plans, the EPA generally acknowledges the CO_2 emissions reduction and climate policy benefits of waste-derived biogenic feedstocks[104] and certain forest- and agriculture-derived

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[103] www.whitehouse.gov/sites/default/files/image/president27sclimateactionplan.pdf.

[104] Types of waste-derived biogenic feedstocks may include: landfill gas generated through the decomposition of MSW in a landfill; biogas generated from the decomposition of livestock

industrial byproduct feedstocks, based on the conclusions supported by a variety of technical studies, including the revised *Framework for Assessing Biogenic Carbon Dioxide for Stationary Sources*. Such waste-derived and certain industrial byproduct biomass feedstocks would likely be approvable as qualifying biomass in a state plan. In addition, given the importance of sustainable land management in achieving the carbon reduction goals of the President's Climate Action Plan, sustainably-derived agricultural and forest biomass feedstocks may also be acceptable as qualifying biomass in a state plan, if the state-supplied analysis of proposed qualifying feedstocks or feedstock categories can adequately demonstrate that such feedstocks or feedstock categories are appropriately reduce CO_2 emissions from affected EGUs.

Many states have recognized the importance of forests and other lands for climate resilience and mitigation, and have developed a variety of sustainable forestry policies, RE incentives and standards, and GHG accounting procedures. Some states, for example Oregon and California, have programs that recognize the multiple benefits that forests provide, including biodiversity and ecosystem services protection as well as climate change mitigation through carbon storage. Oregon has several programs focused on best forest management practices and

waste, biogenic MSW, and/or other food waste in an anaerobic digester; biogas generated through the treatment of waste water, due to the anaerobic decomposition of biological materials; livestock waste; and the biogenic fraction of MSW at waste-to-energy facilities (as discussed in section VIII.G.1.b(3)(c) below).

sustainability, including the Oregon Indicators of Sustainable Forests, that promote environmentally, economically and socially sustainable management of state forests. California’s Forest Practice Regulations support sustained production of high-quality timber while considering ecological, economic and social values, and the state’s Greenhouse Gas Reduction Fund provides resources for forestry projects to improve forest health, maintain carbon storage and avoid GHG emissions from pests, wildfires and conversion to non-forest uses.

Several states focus on sustainable bioenergy, as seen with the sustainability requirements for eligible biomass in the Massachusetts RPS, which, among other requirements, limits old growth forest harvests. Many states employ complementary programs that together work to address sustainable forestry practices. For example, Wisconsin uses a state forest sustainability framework that provides a common system to measure the sustainability of the state’s public and private forests, in conjunction with a series of voluntary best management guideline manuals for sustainable woody biomass and agriculturally-derived biomass. In addition to state-specific programs, some states also actively participate in sustainable forest management or certification programs through third-party entities such as the Sustainable Forestry Initiative (SFI) and the Forest Stewardship Council (FSC). For example, in addition to other state sustainability programs, New York has certified more than 780,000 acres of state forestland to both SFI and FSC's sustainable forest management programs. SFI and FSC have certified more than 63 and 35 million acres of forestland across the U.S., respectively.

These examples demonstrate how states already use diverse strategies to promote sustainable forestry and agricultural management while realizing their unique economic, environmental and RE goals. As states evaluate options for meeting the emission guidelines, they may consider how the role of waste-derived feedstocks as well as sustainably-derived biomass and sustainable forestry and agriculture programs, such as the examples highlighted above, may help them meet their emission reduction goals. In addition, the EPA's work on assessing biogenic CO_2 emissions from stationary sources may also help inform states' efforts to assess the role of different biogenic feedstocks in their plans and broader climate strategies.

In November 2014, the agency released a second draft of the technical report, *Framework for Assessing Biogenic Carbon Dioxide for Stationary Sources*. The revised *Framework,* and the EPA's Science Advisory Board (SAB) peer review of the *2011 Draft Framework*, finds that it is not scientifically valid to assume that all biogenic feedstocks are "carbon neutral" and that the net biogenic CO_2 atmospheric contribution of different biogenic feedstocks generally depends on various factors related to feedstock characteristics, production, processing and combustion practices, and, in some cases, what would happen to that feedstock and the related biogenic emissions if not used for energy production.[105] The EPA is engaging in a second round of targeted peer review with the SAB in 2015.[106] Information in the revised *Framework* and the second SAB peer review process, including stakeholder comments, should assist both states and the EPA in assessing qualifying biomass feedstocks included in state plans.

(2) Biomass co-firing. Affected EGUs may use qualifying biomass co-fired with fossil fuels at an affected EGU. As discussed above in this section, not all forms of biomass are expected to be approvable and states should propose qualifying biomass feedstocks and treatment of biogenic CO_2 emissions in state plans, along with supporting analysis and quality control measures. The EPA will review the appropriateness and basis for such determinations and accounting measures in the course of its review of a state plan.

An affected EGU using qualifying biomass as a fuel must monitor and report both its overall CO_2 emissions and its biogenic CO_2 emissions. If biomass is to be used as an emission reduction measure in a state plan, the plan must specify requirements for reporting biogenic CO_2 emissions from affected EGUs. Reporting requirements for biogenic CO_2 emissions under 40 CFR 98(§§ 98.3(c), 98.36(b)-(d), 98.43(b), and 98.46) are an acceptable default reporting approach that would be approvable

[105] www.epa.gov/climatechange/ghgemissions/biogenic-emissions.html.
[106] www.epa.gov/sab.

when combined with other state plan components. However, the EPA may approve other approaches included in a state plan.

(3) Biomass repowering. Affected EGUs could fully repower to use primarily qualifying biomass. The characteristics of affected sources, as discussed in Section IV.D., include the use of at least 10 percent fossil fuel for applicability of these emission guidelines. An EGU repowering with at least 90 percent biomass fuels instead of fossil fuels becomes a non-affected EGU.[107] An EGU repowering with less than 90 percent biomass would remain an affected EGU and provide a reduction option similar to that described earlier in this section, with the same processes for proposing qualified biomass feedstocks or feedstock categories and biogenic CO_2 emissions evaluation, monitoring and reporting requirements. Entities switching to significantly higher amounts of biomass use may be subject to other permitting requirements outside of this rule.

J. Additional Considerations for Plan Approaches and CO_2 Emission Reduction Measures for Mass-Based State Plans

This section discusses [different approaches for mass-based plans] and accounting for CO_2 emission reduction measures that provide substitute generation for affected EGUs or avoid the need for generation from affected EGUs in mass-based state plans.

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[107] For such an EGU to be considered non-affected, the EGU should be subject to a federally enforceable or practically enforceable condition, expressed in (for example) a construction permit or otherwise, that limits the amount of fossil fuel that may be used to 10 percent or less.

1. [add language on approaches]

2. Accounting for CO_2 emission reduction measures in mass-based state plans

As discussed in section VIII.J, measures that occur at affected EGUs will result in CO_2 emission reductions that are automatically accounted for in reported CO_2 emissions. Other measures that provide substitute generation for affected EGUs or avoid the need for generation from affected EGUs, such as demand-side EE, are automatically accounted for under a mass-based plan to the extent that these measures reduce reported CO_2 emissions from affected EGUs. Unlike under a rate-based plan, no additional accounting is necessary in order to recognize these emission reductions.

K. Additional Considerations for Plan Approaches and CO_2 Emission Reduction Measures for Rate-Based State Plans

This section discusses [different approaches that may be used for rate-based plans] and the use of CO_2 emission reduction measures that provide substitute generation for affected EGUs or avoid the need for generation from affected EGUs in rate-based state plans. These measures may be used to adjust the CO_2 emission rate of an affected EGU under a rate-based state plan. This adjustment may occur when an affected EGU is demonstrating compliance with a rate-based emission standard, or when a state is demonstrating achievement of the CO_2 emission performance rates or applicable rate-based state CO_2 emission goal in the emission guidelines.[108]

1. Approaches for rate-based plans

[add]

2. Adjustments to CO_2 emission rates in rate-based state plans

Section VIII.K.2.a below describes the basic accounting method for adjusting a CO_2 emission rate, as well as eligibility requirements for measures that may be used for adjusting a CO_2 emission rate. Section VIII.K.2.b addresses measures that may not be used to adjust the CO_2 emission rate of an affected EGU in a state plan, and explains the basis for this exclusion. Section VIII.K.2.c addresses measures that reduce CO_2 emissions outside the electric power sector. Such measures may not be counted under either a rate-based or mass-based state plan.

a. Actions taken to adjust the CO_2 emission rate of an affected EGU. This section describes how measures that substitute for generation from affected EGUs or avoid the need for generation from affected EGUs may be used in a state plan to adjust the CO_2 emission rate of an affected EGU. This section discusses the required accounting method for adjusting a CO_2 emission rate, as

[108] Under a state measures plan, as described in section VIII.C.4, a state may adjust the reported CO_2 emission rate of affected EGUs when demonstrating achievement of the CO_2 emission performance rates or applicable rate-based state CO_2 emission goal in the emission guidelines.

well as general eligibility requirements that apply to different categories of measures that may be used to adjust a CO_2 emission rate. Where relevant, this section also discusses additional specific accounting methods and other relevant requirements that apply to different categories of measures.

A CO_2 emission rate adjustment may be applied in different rate-based state plan contexts. For example, in a rate-based emission trading program, adjustments may be applied through the use of ERCs.[109] Alternatively, under a state measures plan that does not employ rate-based trading, adjustments may be applied by the state to the reported CO_2 emission rate of the affected fleet of EGUs. Regardless of the type of plan in which an adjustment is applied, the same basic accounting and general eligibility requirements described in this section will apply.

As discussed in this section, a wide range of actions may be taken to adjust the reported CO_2 emission rate of an affected EGU in order to meet a rate-based emission standard and/or demonstrate achievement of a state CO_2 rate-based emissions goal. All of the measures described in this section will substitute for generation from affected EGUs or avoid the need for generation from affected EGUs, thereby reducing CO_2 emissions. This includes

[109] ERCs may be issued for the measures presented in this section, as well as to affected EGUs that emit at a CO_2 emission rate below their assigned emission rate limit. ERC issuance and trading is discussed in detail in section VIII.G. That section addresses the accounting method for ERC issuance to affected EGUs that perform below their assigned CO_2 emission rate.

RE measures included in the EPA's determination of the BSER, as well as other measures that were not included in the determination of the BSER, such as other RE resources, demand-side EE, CHP, WHP, electricity transmission and distribution improvements, nuclear energy, and international energy imports.

The EPA believes that the broad categories of measures listed in this section address the wide range of actions that are available to reduce CO_2 emissions from affected EGUs under a rate-based state plan. However, the actions that a state could include in a rate-based state plan are not necessarily limited to those described in this section. Other specific actions not listed here may be incorporated in a state plan, provided they meet the general eligibility requirements listed in this section, as well as the other relevant requirements in the emission guidelines.[110] Nor are states required to include in their plans all of the actions that are described in this section.

This section discusses the basic accounting method for adjusting the reported CO_2 emission rate of an affected EGU, through the use of measures that substitute for or avoid generation from affected EGUs. That method is based on adding MWh from such measures to the denominator of an affected EGU's reported CO_2 emission rate (lb CO_2/MWh). Those additional MWh are based on quantified and verified electricity generation or electricity savings from eligible measures. This section also

[110] These requirements are discussed in section VIII.D.

addresses eligibility requirements for resources that are used to adjust an affected EGU's CO_2 emission rate.

(1) General accounting approach for adjusting a CO_2 emission rate. In this final rule, the reported CO_2 emission rate of an affected EGU may be adjusted based on quantified and verified MWh from qualifying zero-emitting and low-emitting resources, as described in sections VIII.G.1.b.(2)-(9) below. These MWh are added to the denominator of an affected EGU's reported CO_2 emission rate, resulting in a lower adjusted CO_2 emission rate.

The measures described in these sections reduce mass CO_2 emissions from affected EGUs by substituting zero- or low-emitting generation for generation from affected EGUs, or by avoiding the need for generation altogether (in the case of resources that lower electricity demand through improved demand-side EE and demand-side management). In both of these cases, generation from an affected EGU is replaced, through substitute generation or a reduction in electricity demand. To the extent that qualifying zero-emitting and low-emitting resources result in reduced generation and CO_2 emissions from an individual affected EGU, those emission impacts are reflected in lower reported CO_2 emissions and a reduction in MWh generation from the affected EGU. However, while there will be a reduction in CO_2 emissions, the fact that both CO_2 emissions and MWh generation are reduced means that such impacts do not alter the reported CO_2 emission rate of the affected EGU. As a result, the MWh of replacement generation must be added to the denominator of the reported CO_2 emission rate, in order to represent those impacts in the form of an adjusted CO_2 emission rate. In this manner, adding MWh from these resources to the denominator of an affected EGU CO_2 emission rate allows mass CO_2 emission reductions from these measures to be fully reflected in an adjusted CO_2 emission rate.

The following provides a simple calculation example of how MWh of replacement generation added to the denominator of an affected EGU's reported CO_2 emission rate results in a lower adjusted CO_2 emission rate. Assume an affected EGU with CO_2 emissions of 200,000 lb and electric generation of 100 MWh during a reporting period. The affected EGU's reported CO_2 emission rate is 2,000 lb/MWh (200,000 lb CO_2/100 MWh = 2,000 lb/MWh). When complying with its rate-based emission limit, the affected EGU submits 10 ERCs, representing 10 MWh of replacement generation.[111] Adding 10 MWh of replacement generation to the reported MWh generation of the affected EGU results in an adjusted CO_2 emission rate of 1,818 lb CO_2/MWh (200,000 lb CO_2/110 MWh = 1,818 lb CO_2/MWh).

In the case of rate-based CO_2 emission standards, an affected EGU demonstrates compliance with the emission standards if the affected EGU's adjusted CO_2 emission rate calculated in

[111] Requirements for the issuance of ERC and a further discussion of how ERCs are used in compliance with rate-based emission limits are addressed in section VIII.G.3.

the aforementioned manner is less than or equal to the applicable CO_2 emission standard rate.[112] In the case of a state measures plan, quantified and verified MWh from eligible state measures are used by the state to administratively adjust the reported CO_2 emission rate of affected EGUs in the aforementioned manner. The CO_2 emission performance rates or rate-based CO_2 goal in the emission guidelines are met if the adjusted CO_2 emission rate of affected EGUs in a state is at or below the specified CO_2 emission rate in a state plan that applies for an identified plan performance period.

Numerous commenters requested that the EPA ensure consistency between goal-setting calculations and the methodology used to demonstrate achievement of a CO_2 emission rate under a state plan. This approach for adjusting a CO_2 emission rate corresponds with how RE, the one component of the BSER that involves adjustment of a CO_2 emission rate, is represented in the CO_2 emission performance rates in the emission guidelines. Specifically, in the calculation of final CO_2 emission performance rates, the MWh of RE are reflected in two adjustments of the rate: a reduction of CO_2 emissions from affected EGUs in the numerator and a one-to-one replacement of affected EGU generation in the denominator, where it is assumed that replaced generation from an affected EGU is subtracted from the

[112] Any ERCs used to adjust a CO_2 emission rate must meet requirements in the emission guidelines, which are described in section VIII.D.

denominator and the same number of zero-emitting MWh are added.[113]

When demonstrating achievement of a CO_2 emission performance rate, the reported CO_2 emissions already reflect the actual emission reductions from the deployment of qualifying non-emitting and low-emitting resources across the regional grid; a further adjustment of CO_2 emissions would double count CO_2 emissions impacts across the grid. Consistent with the EPA's calculation of the CO_2 emission performance rates and state rate-based CO_2 goals in the emission guidelines, the zero-emitting MWhs (from substitute generation or a reduction in electricity demand) must still be added to the denominator of a reported CO_2 emission rate to calculate an adjusted CO_2 emission rate that appropriately reflects the replaced generation. Thus, the resultant rate, where the numerator reflects CO_2 emission reductions from qualifying measures, and the denominator reflects replaced generation, is consistent with the goal-setting calculation.

Several commenters suggested that the EPA consider the regional nature of the electricity grid and how RE and demand-side EE impacts generation and CO_2 emissions across the grid when accounting for the impacts of RE and demand-side EE measures in a rate-based plan approach. This MWh accounting structure corresponds with the regional treatment of RE resources in the

[113] For a detailed discussion of this method, see Section VI.C.3. Form of the Performance Rates, in the Equation subsection.

BSER that provide substitute generation in the EPA-calculated CO_2 emission performance rates in the emission guidelines. Consistent with assumptions used in calculating the CO_2 emission performance rates in the emission guidelines, affected EGUs and states can take full credit for the MWh resulting from eligible measures they are responsible for deploying, no matter where those measures are implemented. CO_2 emission reductions from the eligible measures may occur across the region; however, an affected EGU or a state may only take credit for avoided CO_2 emissions at that affected EGU or set of EGUs in question, as reflected in the reported stack CO_2 emissions of affected EGUs.

Because of the separate accounting of MWhs and CO_2 emissions, with emission impacts inherent in reported stack CO_2 emissions and zero-emitting MWh impacts requiring explicit adjustments, the accounting method corresponds with the use of MWh-denominated ERCs in the rate-based emission trading framework specified in this rule. The accounting method only requires a quantification of the MWh generated or avoided by an eligible measure, and thus credits or adjustments can be denominated in MWh and do not need to represent an approximation of the CO_2 emission reductions that result from those MWhs. This creates a crediting system or rate adjustment process that is simpler to implement than one that requires an approximation of avoided CO_2 emissions.

The MWh accounting method also creates a crediting system or rate adjustment process that is indifferent to the rate-based CO_2 emission goals of individual states, or the specific CO_2 emission rate standards that states may apply, and the relative stringency of those goals or standards. Use of ERCs in rate-based emission trading programs is addressed in detail in section VIII.G.3. As a result, the MWh accounting method addresses interstate effects, because it inherently accounts for how generation replacement and CO_2 emission reduction impacts may cross state borders. For example, if the accounting method was informed by avoided CO_2 emission rates, it could create perverse incentives for development of zero- or low-emitting resources in states that result in the greatest calculated estimate of CO_2 emission reductions for each replacement MWh. Instead, this accounting method is indifferent to avoided CO_2 emission rates and creates the same number of zero-emitting credits or adjustment for each MWh of energy generation or savings, wherever they occur. For a detailed discussion on how the accounting method addresses interstate effects, see section VIII.G.2.

(2) General eligibility requirements for resources used to adjust a CO_2 emission rate. The EPA is finalizing certain general eligibility requirements for resources used to adjust a CO_2 emission rate. These requirements align eligibility with certain factors and assumptions used in establishing the BSER, and by extension, application of the BSER to the performance levels established for affected EGUs in the emission guidelines, as well

as state rate and mass CO_2 goals. As a result, the requirements ensure that measures that may be used in a state plan are treated consistently (to the extent possible) with the EPA's assessment of the BSER.[114] These general requirements also address potential interactions among rate and mass plans, as discussed more fully in section VIII.G.2.

As discussed in the subsections that follow, the general eligibility criteria address:

- the date from which MWh from eligible measures may be counted, and applied toward adjusting a CO_2 rate;
- the date from which eligible measures may be installed (e.g., installation of RE generating capacity and installation of EE measures); and
- the need to demonstrate that eligible measures replace or avoid generation from affected EGUs.

(a) Eligibility date for MWh generation and savings. Electricity generation and electricity savings that occur during a plan performance period may be applied to adjust a CO_2 emission rate. Specifically, this means that any quantified and verified MWh of electricity generation or electricity savings that occur in 2022 and future years, from an eligible measure, may be applied toward

[114] For example, eligibility requirements include installation dates for eligible RE measures that may be used in a state plan. These dates generally align with the dates used for broadly defining incremental RE resources that were considered in establishing the BSER.

adjusting a CO_2 emission rate. The eligible measures themselves may be installed in any year after 2012, as described below.[115] For example, MWh generation in 2022 from a wind turbine installed in 2013 may be applied toward adjusting a CO_2 emission rate.

Further, as discussed in section VIII.C.2.a, a MWh of generation or savings that occurs in 2022 or a subsequent year may be carried forward (or "banked") and applied in a future year. For example, a MWh of RE generation that occurs in 2022 may be applied to adjust a CO_2 emission rate in 2023 or future years, without limitation.[116] These MWh may be banked from the interim to final compliance periods.

The EPA notes that states can submit a rate-based state plan that encourages early action by allowing MWhs generated from 2013-2021 to be used to adjust the CO_2 rate of affected EGUs during the plan performance period (2022 and subsequent years). In order for this type of provision to be approvable in a state plan, it must meet certain conditions. These MWhs must be from eligible measures implemented after 2012. The state plan must provide for adjustment of CO_2 emission performance rates or rate-based state CO_2 goals (applied during the plan performance periods in 2022 and future years) downward based upon the number of eligible MWhs from 2013-2021, such that the level of emission reductions is

[115] For demand-side EE, this eligibility date may require special considerations for EM&V plans. EM&V requirements are addressed in subsection VIII.C.3.

[116] Similarly, as discussed in section VIII.C.2.b.(2).(a), allowances may be banked in a mass-based trading program.

equivalent to or more stringent than that which would have been achieved had eligible MWh been limited to those generated during the plan performance periods in 2022 and future years. This downward adjustment of CO_2 emission performance rates or rate-based state CO_2 goals must be calculated based upon a projection of total CO_2 emissions, total MWh generation from affected EGUs, and total ERCs that would have been used to demonstrate compliance if the state had elected to meet the CO_2 emission performance rates or rate-based state CO_2 goals using only eligible MWh issued in 2022 and subsequent years.

(b) Eligibility date for installation of RE/EE and other measures. RE generating capacity and demand-side EE measures that are installed after 2012 are eligible for use in adjusting a CO_2 emission rate. This aligns with treatment of RE in the BSER. Other eligible measures, such as CHP, nuclear power and DSM, also must be installed after 2012. This 2012 date applies consistent eligibility requirements to all forms of zero- and low-emitting eligible generating capacity that may be used to adjust a CO_2 emission rate. As described above, only the MWh of energy savings that occur in 2022 and subsequent years as a result of these measures may be applied toward adjusting a CO_2 emission rate.

This eligibility date criterion is consistent with the date of installation for “incremental” RE capacity that is included in BSER building block 3, which is the basis for RE MWh incorporated in the CO_2 emission performance rates for affected EGUs in the emission guidelines. For more information on RE in the BSER, see section V.E. Many commenters asserted that proposed state goals did not sufficiently account for actions states take that reduce CO_2 emissions prior to the first plan performance period, and therefore requested that MWhs of electricity generation or electricity savings that occur prior to the first plan performance period be eligible to apply toward adjusting the CO_2 emission rates of affected EGUs.

The EPA recognizes the importance of early state action as the basis for significant CO_2 emission reductions and as a key part of enabling state plans to achieve the CO_2 emission performance levels or state CO_2 goals. The ability to count eligible measures installed in 2013 and subsequent years for the MWhs they generate during a plan performance period provides significant recognition for early action, corresponding with the BSER framework that is based on cost-effective actions that many sources are already doing, while still conforming to CO_2 performance rates and state goals that are forward-looking. Commenters concerns about treatment of early actions are further addressed by changes from proposal to the BSER assumptions and the methodology used by the EPA to establish the CO_2 emission performance levels and rate-based state CO_2 goals in the emission guidelines. The specifics of these changes are addressed in section V.A.3. Three examples of those changes are provided below.

First, affected EGUs that have maximized their CO_2 emission reduction opportunities available through early action will be better positioned to meet the BSER technology-source specific CO_2 emission rate that is uniformly applied to all affected EGUs in a technology category. For example, a steam generating unit that has already reduced its CO_2 emission rate through a heat rate improvement may have a CO_2 emission rate of 2,000 lb/MWh whereas its rate was 2,100 lb/MWh prior to the improvement. Therefore, it has less distance to cover to meet the technology-specific CO_2 emission performance rate for steam generating units finalized in this action.

Second, generation from existing RE capacity installed prior to 2013 has been excluded from the EPA's calculation of the CO_2 emission performances rates in the emission guidelines. That RE generating capacity will still provide zero-emitting generation to the grid and will better position states and affected EGUs to meet the CO_2 performances rates or state rate- or mass-based CO_2 goals.

Third, commenters expressed concern that demand-side EE targets as part of proposed state goals reflected an assumption of installation of increased EE measures starting 2017. Because demand-side EE is not used in calculating the CO_2 emission performance rates in the emission guidelines, this is no longer the case. Furthermore, eligible demand-side EE actions that occur after 2012 can be applied toward adjusting the CO_2 emission rates of affected EGUs.

(c) <u>Demonstration that measures substitute for grid generation</u>. Eligible measures must be grid-connected. This eligibility criterion aligns with RE generation in building block 3 of the BSER, which substitutes for the need for generation from affected EGUs.

All EE measures must result in electricity savings at a building, facility, or other end-use location that is connected to the electricity grid. EE measures only avoid electric generation from grid-connected EGUs if the electrical loads where the efficiency improvements are made are interconnected to the grid.

Commenters sought clarity on this issue, so the EPA is providing this requirement as part of the final rule. Some commenters advocated for the inclusion of measures that were not grid connected as eligible resources, arguing that some of these measures substituted for non-affected EGUs and resulted in reductions in CO_2 emissions. However, eligible measures must be able to substitute for generation from affected EGUs as defined under this rule, and thus must be tied to the electrical grid.

(d) <u>Geographic eligibility</u>. RE generation and demand-side EE measures may occur in any state or territory, with certain limitations, as described below. To the extent these measures are tied to a state plan,[117] these measures may be used to adjust a

[117] As used here, a measure is "tied to a state plan" if it is

CO_2 emission rate, regardless of whether the RE generation or demand-side EE savings occur inside or outside the state or territory.[118] This approach is generally consistent with the approach used in building block 3 of the BSER, which reflects regionally available RE and interstate effects. It also recognizes that RE and demand-side EE measures have impacts on electricity generation across the electricity system, both within and beyond a state's borders. A more in-depth discussion of the basis for treatment of in-state and out-of-state RE and EE is provided below.

For consistency, this geographic eligibility criterion applies to all other eligible measures that are used to adjust a CO_2 emission rate under a state plan. These measures will have similar interstate impacts as RE and demand-side EE on electricity generation across the interconnected electricity system.

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issued an ERC under approved procedures in a rate-based emission standards plan, or represents quantified and verified MWh energy generation or energy savings achieved by an approved state measure in a state measures plan.

[118] For example, under a rate-based emission standard with credit trading, ERCs may be issued for qualifying actions that occur both inside and outside the state, provided the measures meet requirements of EPA-approved state regulations and the provider applies to the state for the issuance of ERCs. Similarly, under a state measures plan, a state might include state requirements such as an RPS, where compliance with the RPS can be met through out-of-state RE generation. In this plan context, MWh of RE generation used to comply with the state RPS could be used by the state to adjust the CO_2 emission rate of the fleet of affected EGUs in the state when demonstrating that its plan has achieved the state's rate-based CO_2 goal.

State plans must demonstrate that emission standards and state measures (if applicable) are non-duplicative. Given the geographic eligibility approach described here, this includes a demonstration that a state plan does not allow recognition of a MWh, for use in adjusting the CO_2 emission rate of an affected EGU, if the MWh is being or has been used for such a purpose under another state plan. Discussion of how such a demonstration can be made in the context of a rate-based emission trading program is in section VIII.D.

The EPA received many comments on the treatment of in-state and out-of-state RE and demand-side EE. Most commenters recommended crediting of both in-state and out-of-state RE and demand-side EE measures, similar to the final rule approach. Commenters argued that this approach makes sense based on the nature of the interconnected electricity grid and allows states and utilities to fully account for their RE and demand-side EE efforts, whether that RE or EE, and its related impacts, occurs inside or outside of their state. Some commenters expressed concerns that, at proposal, states with significant RE resources had large amounts of existing RE capacity included in their state CO_2 goals, but that RE was functionally credited to other states for use in meeting their goals because it was associated with measures (such as an RPS) likely to be included in another state’s plan. This concern has been addressed through changes in the BSER RE assumptions in the final rule. This includes regionalization of the RE building block, and removal of existing RE capacity constructed prior to 2012 from the building block. The result of these changes is that the RE incorporated in the BSER is more equally shared across states.

(i) Measures that occur in states with mass-based plans. As discussed above, eligible measures for adjusting the CO_2 emission rate of an affected EGU may occur in any state, with certain conditions. This includes eligible measures that occur in a state with an EPA-approved plan that is meeting a state mass-based CO_2 goal. However, measures that occur in such mass-based states must meet additional eligibility criteria to be used to adjust the CO_2 emission rate of an affected EGU in a state with a rate-based plan.

These criteria are intended to address the fact that eligible measures should lead to substitution of generation from affected EGUs, with related impacts on CO_2 emissions from affected EGUs. Where states with mass-based plans implement mass-based CO_2 emission standards, CO_2 emissions reductions from affected EGUs must occur in order to comply with these emission standards and, unlike the rate-based approach, zero- and low-emitting MWhs do not play a specified role in demonstrating that the mass-based standards have been met.[119] Since they are not

[119] Where such measures substitute for generation from affected EGUs subject to a mass CO_2 emission limit, such measures reduce the cost of meeting those mass emission limits, but do not result in incremental CO_2 emission reductions.

counted in the mass-based demonstration, eligible measures located in mass-based states could be used in a state with a rate-based plan to adjust the CO_2 emission rate of affected EGUs. Such adjustments would obviate the need for comparable CO_2 emission reductions at affected EGUs in the rate-based state or the use of other measures to make a rate adjustment. In this scenario, to the extent that eligible measures substitute solely for generation from affected EGUs in a state with mass-based emission limits, and are also used to adjust the reported CO_2 emission rate of affected EGUs in a rate-based state, no incremental CO_2 emissions reductions would occur in the rate-based state as a result of the eligible measures.[120] The result would be a loss in net CO_2 emission reductions that would otherwise occur across the two states. These dynamics are further addressed in section VIII.G.2.

For measures providing zero- or low-emitting generation located in a mass-based state, it must be demonstrated that the energy generated is delivered to meet electricity load in a state with a rate-based plan.[121] Some examples of documentation that can serve as a demonstration include a power delivery contract or power purchase agreement. The EPA is giving states flexibility regarding the nature of this demonstration, but a state plan must

[120] As used here, incremental emission reductions refers to emission reductions that are above and beyond what would be achieved solely through compliance with the emission standards in the mass-based state.

[121] This does not need to necessarily be the state where the MWh of energy generation from the measure is used to adjust the CO_2 emission rate of an affected EGU.

describe the nature of the required demonstration and have it be approved by the EPA.

Under an emission standards plan, this demonstration must be made by the provider of the measure seeking ERC issuance under the rate-based emission standards in a rate-based state, as part of the eligibility application for the measure.[122] Under a state measures plan, this demonstration must be made by the rate-based state as part of its demonstration of how its state measures meet the CO_2 emission performance rates or achieve the state rate-based CO_2 emission goal for affected EGUs.[123] In the case of either an emission standards plan or state measures plan, the rate-based state must include in its state plan provisions that describe what it will consider a sufficient demonstration of geographic eligibility for zero- or low-emitting generation under rate-based emission standards, or geographic eligibility of state measures that can be used to adjust the reported CO_2 emission rate of affected EGUs.

Further examples of eligible demonstrations and how they should be outlined in state plans is provided in section VIII.G.2.

(ii) Measures that occur in states and territories that are not interconnected to the grid or do not have affected EGUs. States

[122] Requirements for ERC issuance are addressed in subsection VIII.C.2.

[123] This demonstration is part of a state's annual report to the EPA, outlining the eligibility of MWh used to adjust the reported CO_2 emission rates of affected EGUs under a rate-based state measures plan.

and territories that are not interconnected to the grid in the continental U.S. or that do not have any affected EGUs within their borders may be providers of credits to adjust CO_2 emission rates. In its supplemental proposal for this proposed rulemaking, the EPA sought comment on whether or not jurisdictions without affected fossil fuel generation units subject to the proposed emission guidelines should be authorized to participate in state plans. Commenters were supportive of allowing those jurisdictions without affected EGUs the opportunity to participate in state plans. CO_2 reduction measures in areas without affected EGUs have the potential to provide cost-effective opportunities to reduce emissions and should be available on a voluntary basis to affected EGUs. Commenters noted that some tribes, for example, have many untapped RE resources that could be developed, and they should be able to realize the benefits of contributing to a state plan. Commenters stated that because of the integrated nature of the U.S. electricity grid, it is appropriate to allow all jurisdictions with the ability to contribute to and benefit from CO_2 emission reductions or CO_2 emission rate adjustments.

For rate-based states and territories, they must adhere to EM&V standards, installation dates, and any other criteria that apply to all states. Section VIII.G.3 below identifies and discusses the EM&V criteria used to quantify MWh savings from demand-side EE and generation from zero-emitting sources. States, including areas of Indian country, that do not have any affected EGUs may provide ERCs to adjust CO_2 emissions provided they are connected to the continental U.S. grid and have a power purchase agreement or contract for delivery of the zero- or low-emission power, along with meeting the other requirements for eligibility. Mass-based states and territories are not allowed to provide ERCs for zero- or lower-emission power generation if they are not connected to the continental U.S. grid and, hence, not able to also deliver the power. For demand-side EE adjustments where there is no power delivery, the emission reductions must meet the demonstration criteria that also applies to demand-side EE reductions in all other mass-based states.

(iii) Measures that occur outside the U.S. The EPA will work with states using the rate-based approach that are interested in allowing the use of RE and demand-side EE from outside the U.S. to adjust CO_2 emission rates. In these cases, all conditions for creditable domestic RE and demand-side EE must be met, including that RE and demand-side EE resources must be incremental and installed after 2012, and all EM&V standards must be met. In addition, the country generating the ERCs must be connected to the U.S. grid, and, specifically for RE, there must be a power purchase agreement or other contract for delivery of the power with an entity in the U.S. For demand-side EE adjustments where there is no power delivery, the emission reductions must meet the demonstration criteria that also applies to demand-side EE reductions in mass-based states. RE generation capacity outside the U.S. that existed prior to 2012 but was not exported to the U.S. is not considered new or incremental generation and, therefore, not eligible for adjusting CO_2 emission rates under this rule. For example, a new transmission interconnection to existing RE in Canada would not be considered incremental. See below for more specifics regarding the use of incremental hydroelectric power in a rate-based approach.

The EPA received comments encouraging the use of international zero-emitting electricity imports in state plans, particularly hydroelectric power from Canada. Canada currently provides states such as Minnesota and Wisconsin with RE through existing grid connections. New projects are in various stages of development to increase generating capacity, which could be called upon as a base load resource to supplement intermittent forms of RE generation. Commenters said that the EPA should permit the use of all incremental hydropower—both domestic and international—towards EGU CO_2 emission rate adjustments providing that double-counting can be prevented; and the EPA acknowledges this may be allowable, as long as the specified criteria have been met.

(3) RE and demand-side EE. RE[124] and demand-side EE measures may be used to adjust a CO_2 emission rate, provided they meet the general eligibility requirements outlined above and the MWh electricity generation or electricity savings are properly

[124] As used in this section, RE includes electric generating technologies using RE resources, such as wind, solar, geothermal, hydropower, biomass and wave and tidal power.

quantified and verified.[125]

Many commenters supported using RE deployment as measures to adjust the CO_2 emission rate of affected EGUs. Some commenters specifically agreed with the EPA's determination that only new and incremental RE (including hydropower) should be used to adjust CO_2 emission rates. Those commenters objected to counting existing RE that are already embedded in the baseline emissions and generation mix. A significant number of commenters supported the integration of RE into a rate-based credit trading system.

Certain additional requirements apply for hydropower and biomass (including waste-to-energy), as described below.

(a) Hydroelectric power. Consistent with other types of RE, new hydroelectric power generating capacity installed after 2012 is eligible for use in adjusting a CO_2 emission rate. In addition, a capacity uprate at an existing hydroelectric power resource (i.e., an uprate to generating capacity originally installed as of 2012 or earlier) is also eligible to adjust a CO_2 emission rate. The capacity uprate must occur after 2012. Such uprates to capacity represent incremental capacity added after 2012, which we refer to as "incremental hydroelectric power."

Generation (in MWh) from incremental hydroelectric power generating capacity is determined as follows. The incremental

[125] All state plans must demonstrate that measures included in the plan are quantifiable and verifiable. See section VIII.C.2 for discussion of requirements for the issuance of ERCs, and section VIII.C.3 for discussion of EM&V requirements for use of RE and demand-side EE in a state plan.

generating capacity (in nameplate MW) is divided by the total uprated generating capacity (in nameplate MW) and then multiplied by generation output (in MWh) from the uprated generator. For example, if a hydroelectric power plant expands generating nameplate capacity from 100 MW to 125 MW and generation output increased to 1,000 MWh, then 200 MWh ((25 MW/125 MW) * 1,000 MWh) is eligible for use in adjusting a CO_2 emission rate, regardless of the overall level of generation for the period.[126]

Relicensed facilities are considered existing capacity and, therefore, are not eligible for use in adjusting a CO_2 emission rate, unless there is a capacity uprate as part of the relicensed permit. In such a case, only the incremental capacity is eligible for use in adjusting a CO_2 emission rate.

The EPA noted that many commenters preferred that generation from hydropower displace generation from fossil sources. One commenter suggested that existing zero-emitting sources, including hydropower, do not reduce emissions from existing fossil generation, but that new or uprated zero-emitting sources would, because of their low variable rate, reduce fossil emissions. Several commenters recommended allowing incremental generation from new or uprated zero-emitting sources, including hydropower, be available for compliance. One commenter recognized the difficulty of quantifying emission reductions due to uprated zero-emitting sources. The EPA believes the approach described is

[126] For example, the overall generation from the uprated hydroelectric power plant may be higher or lower than generation levels that occurred at the plant prior to the capacity uprate.

appropriate.

(b) Biomass. RE generating capacity installed after 2012 that uses qualifying biomass as a fuel source is eligible for use in adjusting a CO_2 emission rate.[127] As discussed in section VIII.G.1.a.(2)(c), a state should propose qualifying biomass feedstocks and treatment of biogenic CO_2 emissions in its plan, along with supporting analysis and quality control measures, and the EPA would review the appropriateness and basis for such determinations in the course of its review of a state plan. Where an RE generating unit uses qualifying biomass, as designated in an approved state plan, MWh generation from the unit could be used to adjust a CO_2 emission rate. Considerations for the use of biomass in state plans are discussed in section VIII.G.1.a(2)(c)(i).

(c) Waste-to-energy. Use of qualifying biomass may include the biogenic portion of MSW combusted in a waste-to-energy facility.[128] With regard to assessing qualifying biomass specified in state plans, the EPA generally acknowledges the CO_2 emission reduction and climate policy benefits of waste-derived biomass, based on the conclusions supported by a variety of technical studies, including the revised *Framework for Assessing Biogenic Carbon Dioxide for Stationary Sources*.[129] Such waste-derived

[127] As with other RE, only generating capacity installed after 2012 would be eligible for use in adjusting a CO_2 emission rate.
[128] As with other RE, only generating capacity installed after 2012 would be eligible for use in adjusting a CO_2 emission rate.
[129] http://www.epa.gov/climatechange/downloads/Framework-for-

biomass feedstocks would likely be approvable as qualifying biomass in a state plan. As described in Section VIII.G.1.a.(2)(c), states should propose qualifying biomass feedstocks and treatment of biogenic CO_2 emissions in state plans, along with supporting analysis, and the EPA would review the appropriateness and basis for such determinations in the course of its review of a state plan. Considerations for the use of biomass in state plans are discussed in section VIII.G.1.a.(2)(c)(i).

MSW can be directly combusted in waste-to-energy facilities to generate electricity as an alternative to landfill disposal. In the U.S., almost all incineration of MSW occurs at waste-to-energy facilities or industrial facilities where the waste is combusted and energy is recovered.[130] Total MSW generation in 2012 was 251 million tons, but of that total volume generated, almost 87 million tons were recycled and composted.[131] Increasing demand for electricity generated from waste-to-energy facilities could increase competition for waste stream materials – including discarded organic waste materials – which could cause diversion of these materials from existing or future efforts promoting waste reduction, composting, and recycling. The EPA and many states have recognized the importance of integrated waste

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Assessing-Biogenic-CO2-Emissions.pdf.

[130] Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2012. http://www.epa.gov/climatechange/ghgemissions/usinventoryreport.html.

[131] http://www.epa.gov/osw/nonhaz/municipal/pubs/2012_msw_fs.pdf.

materials management strategies that emphasize a hierarchy of waste prevention and all other productive uses of waste materials to reduce the volume of disposed waste materials.[132] For example, Oregon and Vermont have strategies that emphasize waste prevention, followed by reuse, then recycling and composting materials prior to treatment and disposal.[133]

Information in the revised *Framework for Assessing Biogenic CO_2 Emissions from Stationary Sources* and other technical studies and tools (e.g., EPA Waste Reduction Model) should assist both states and the EPA in assessing the role of biogenic feedstocks used in waste-to-energy processes, where use of such feedstocks is included in a state plan.[134]

When developing their plans, states planning to use waste-to-energy as an option for the adjustment of a CO_2 emission rate should assess both their capacity to strengthen existing or implement new waste reduction, reuse, recycling and composting programs, and measures to minimize any potential negative impacts of waste-to-energy operations on such programs. States must include that information in their plan submissions.

Only electric generation at a waste-to-energy facility that is related to the biogenic fraction of MSW and that is added after 2012 is eligible for use in adjusting a CO_2 emission rate. Total electric generation from the facility must be prorated

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[132] http://www.epa.gov/wastes/nonhaz/municipal/hierarchy.htm.

[133] http://www.anr.state.vt.us/dec/wastediv/WastePrevention/main.htm.

[134] http://epa.gov/epawaste/conserve/tools/warm/Warm_Form.html.

based on the proportion of biogenic content of MSW. This can be achieved through periodic sampling of the biogenic fraction of the MSW used as fuel at a waste-to-energy facility, or based on the proportion of biogenic CO_2 emissions to total CO_2 emissions from the facility. Measuring the proportion of biogenic to fossil CO_2 emissions can be performed via ASTM D-6866-06 testing or other methods (ASTM, 2006; Bohar, et al. 2010). For example, where the biogenic fraction of MSW is 50 percent by weight, only the proportion of MWh output attributable to the biogenic portion of MSW at the waste-to-energy facility may be used to adjust an affected EGU CO_2 emission rate. Alternatively, where biogenic CO_2 emissions represent 50 percent of total reported CO_2 emissions, a facility would need to estimate the fraction of biogenic to fossil MSW utilized and the net energy output of each component (based on relative higher heating values) to determine the percent of the MWh output from the waste-to-energy facility that may be used to adjust an affected EGU CO_2 emission rate. A state plan must propose a method for determining the proportion of total MWh generation from a waste-to-energy facility that is eligible for use in adjusting a CO_2 emission rate.

Where biogenic CO_2 emissions as a proportion of total CO_2 emissions from a waste-to-energy facility are used to prorate total MWh output that may be used to adjust a CO_2 emission rate, the state plan must specify requirements for reporting biogenic CO_2 emissions from the facility. Reporting requirements for biogenic CO_2 emissions under 40 CFR 98 (§§ 98.3(c), 98.36(b)-(d), 98.43(b), and 98.46) are an acceptable default reporting approach that would be approvable. However, the EPA may approve other approaches included in a state plan.

The EPA received multiple comments supporting the use of waste-to-energy as part of a state's plan for reducing CO_2 emissions. Some commenters expressed concern that non-biogenic materials, such as plastics and metal, would be incinerated along with biogenic materials. As discussed above, only electric generation related to the biogenic fraction of MSW at a waste-to-energy facility added after 2012 is eligible for use in adjusting a CO_2 emission rate. The EPA also received comments that expressed concern about the potential negative impacts on recycling and waste reduction efforts, while other commenters asserted that waste-to-energy practices encourage recycling programs. Some commenters also expressed concern about what treatment would be approvable for emissions from waste-to-energy practices. As discussed above, potential negative impacts from waste-to-energy production on recycling, waste reduction, and composting programs should be evaluated and efforts to mitigate negative impacts must be discussed in state plans.

(4) <u>Demand-side management</u>. Avoided MWh of electricity use that result from demand-side management may be used to adjust a CO_2 emission rate. Eligible DSM actions are those that are non-emitting and avoid, rather than shift, the use of electricity by

an electricity end-user.[135] The MWh that may be used for such an adjustment are determined based on the MW of demand reduction multiplied by the hours during which such a demand reduction is achieved (MW of demand reduction x hours = MWh avoided). DSM measures must be appropriately quantified and verified, in accordance with requirements in the emission guidelines, as discussed in section VIII.C.3.

(5) Energy storage. Energy storage may not be directly recognized as an eligible measure that can be used to adjust a CO_2 emission rate, because storage does not directly substitute for electric generation from the grid or avoid electricity use from the grid.[136] The electric generation that is input to an energy storage unit may be used to adjust a CO_2 emission rate, but the output from the energy storage unit may not.[137] However, energy

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[135] An example is a utility direct load control program, such as those where customer air conditioning units are cycled during periods of peak electricity demand. Actions that shift electricity demand from one time of day to another are not eligible, as these measures do not avoid electricity use from the grid. Use of emitting generators as a DSM measure are also not eligible.

[136] Energy storage depends on a generation source, either from a utility-scale EGU (e.g., a fossil EGU, a wind turbine, etc.) or a distributed generation source at an electricity end-user (e.g., a PV system installed at a building).

[137] This approach focuses on counting the qualifying electric generation, which may be an input to an energy storage unit. Counting both the generation input to energy storage and the output from the energy storage unit would be a form of double counting. The electric generation that is stored may be counted; the subsequent output from the storage unit may not. Furthermore, it may be impossible in certain instances to determine the specific EGUs that supplied an energy storage unit, in some utility-scale applications of energy storage.

storage can be used as an enabling measure that facilitates greater use of RE, which can be used to adjust a CO_2 emission rate. For example, utility scale energy storage may be used to facilitate greater grid penetration of RE generating capacity and can also be used to store RE generation that may have otherwise been shed in times of excess generating capacity. Likewise, on-site energy storage at an electricity end-user can enable greater use of RE to meet on-site electricity demand.[138]

The EPA received multiple comments regarding the overall merits of energy storage. Consistent with the discussion above, the majority of commenters observed that storage technology enables greater grid penetration of RE and supports more efficient and effective operations of both RE and fossil-fuel plants. Commenters further noted that energy storage can provide RE to the grid when it is most needed, while simultaneously taking pressure off fossil-fuel plants to respond to sudden shifts in demand. Despite broad acknowledgment of the benefits of storage, public comments underscore its indirect and supporting role in providing zero-emission MWh to the grid (consistent with the EPA's decision to exclude energy storage as an eligible measure that can be used to adjust a CO_2 emission rate).

(6) Transmission and distribution measures. Electricity T&D

[138] For example, battery storage at a building with solar PV can enable the PV system to meet the building's entire electrical load, by storing energy during times of peak PV system output for later use when the sun is not shining.

measures that improve the efficiency of the T&D system and/or reduce electricity use may be used to adjust a CO_2 emission rate. This includes T&D measures that reduce losses of electricity during delivery from a generator to an end-user (sometimes referred to as "line losses"[139]) and T&D measures that reduce electricity use at the end-user, such as conservation voltage reduction (CVR).[140] The EPA received many comments in support of advanced energy technologies, including energy storage and transmission and distribution upgrades, and including these technologies in the suite of potential measures that states could consider for emission rate adjustments in their state plans. Comments pointed out that in addition to helping achieve emission standards, T&D efficiency improvements make the

[139] T&D system losses (or "line losses") are typically defined as the difference between electricity generation to the grid and electricity sales. These losses are the fraction of electricity lost to resistance along the T&D lines, which varies depending on the specific conductors, the current, and the length of the lines. The Energy Information Administration (EIA) estimates that national electricity T&D losses average about 6% of the electricity that is transmitted and distributed in the United States each year.

[140] Volt/VAR optimization (VVO) refers to coordinated efforts by utilities to manage and improve the delivery of power in order to increase the efficiency of electricity distribution. VVO is accomplished primarily through the implementation of smart grid technologies that improve the real-time response to the demand for power. Technologies for VVO include load tap changers and voltage regulators, which can help manage voltage levels, as well as capacitor banks that achieve reductions in transmission line loss. VVO efforts are often closely related to conservation voltage reduction (CVR), which are actions taken to reduce initial delivered voltage levels in feeder transmission lines while remaining within the 114 volt to 126 volt range required at the customer meter (based on ANSI C84.1 standards).

grid more robust and flexible, as well as delivering environmental benefits. In many parts of the country, grid operators, transmission planners, transmission owners and regulators are already taking steps to expand and modernize T&D networks. Commenters suggested that the EPA clarify the eligibility and criteria under which such measures would be permitted in a state plan.

To be eligible, T&D measures must be installed after 2012. This general eligibility requirement is discussed above in section VIII.C.1.b.(2)(b). The MWh of avoided losses or reduction in end-use that result from T&D measures must be appropriately quantified and verified, as discussed in section VIII.C.3. To this point, the predominant view expressed in public comments was broad acknowledgement that EM&V for T&D strategies is maturing in tandem with their increasing adoption by states and utilities. For example, several commenters referenced protocols and procedures currently under development and already in usage for quantifying MWh savings from CVR. This development in EM&V for T&D strategies was cited as a rationale for their inclusion as an eligible measure that can be used to adjust a CO_2 emission rate.

(7) Water system efficiency. Water efficiency programs that improve EE at water and wastewater treatment facilities also provide demand-side EE savings opportunities. The EPA received comments supporting the use of water sector EE programs and projects. Commenters identified water and wastewater utilities as particularly well-suited for participating in EE programs and providing a source of electricity savings. Investments such as

replacing pumps and other aging equipment and repairing leaks can result in greater EE. The EPA agrees that these electricity savings should be eligible for adjustments to CO_2 emission rates at affected EGUs.

To be eligible, water efficiency measures must be installed after 2012. This general eligibility requirement is discussed above in section VIII.C.1.b.(2)(b). The MWh of avoided electricity use that result from water efficiency measures must be appropriately quantified and verified, as discussed in section VIII.C.3.

(8) Nuclear power. As is discussed in section V.A.3., upon consideration of comments received, the EPA does not include either nuclear generation from existing or under construction units in the determination of the BSER. In addition to comments received on the provisions for determining the BSER, the EPA also received comments requesting that the EPA allow all generation from nuclear generating units to be recognized as an eligible measure that can be used to adjust a CO_2 emission rate. Commenters also recommended that the EPA consider nuclear generating units and RE generating units in a consistent manner for CO_2 emission rate adjustments in state plans. We agree with comments that nuclear generation and RE should be treated consistently when it comes to CO_2 emission rate adjustments.

The EPA has determined that generation from new nuclear units and capacity uprates at existing nuclear units will be eligible for use in adjusting a CO_2 emission rate. However, consistent with the reasons discussed for not including the preservation of existing nuclear capacity in the BSER – namely, that such preservation does not actually reduce existing levels of CO_2 emissions from affected EGUs – preserving generation from existing nuclear capacity is not eligible for use in adjusting a CO_2 emission rate.

In contrast, any incremental zero-emitting generation from new nuclear capacity would be expected to replace generation from affected EGUs and, thereby, reduce CO_2 emissions; and the continued commitment of the owner/operators to completion of the new units and improving the efficiency of existing units through uprates can play a key role in state plans. Therefore, consistent with treatment of other low- and zero-emitting generation, new nuclear power generating capacity installed after 2012 and incremental generation resulting from nuclear uprates after 2012 are measures eligible for adjusting a CO_2 emission rate. However, existing nuclear units (i.e., those that originally commenced operation in 2012 or earlier years) that receive operating license extensions are not eligible for use in adjusting a CO_2 emission rate, except where such units receive a capacity uprate as a result of the relicensing process. Only the incremental capacity from the uprate is eligible for use to adjust a CO_2 emission rate. Applicable generation (in MWh) from incremental nuclear power is determined in the same manner as that described for incremental hydroelectric power above.

(9) CHP units. Electric generation from non-affected CHP units[141] may be used to adjust the CO_2 emission rate of an affected EGU, as CHP units displace emissions from an on-site boiler and electricity from the grid. Non-affected CHP units that meet the eligibility criteria under section VIII.G.1.b.(2) can be considered under this option. In most cases, a CHP unit would be a low-emitting CO_2 source and therefore the MWh output would need to be prorated to account for the emissions. A denominator approach consistent with the accounting approach for EE and RE, can be taken.

The CHP unit's electrical output would be prorated based on the CO_2 emission rate of the electrical output associated with the CHP unit.[142] The incremental rate would be relative to the applicable CO_2 emission rate for affected EGUs in the state and

[141] The accounting treatment described in this section is for a "topping cycle" CHP unit. A topping cycle CHP unit refers to a configuration where fuel is first used to generate electricity and then heat is recovered from the electric generation process to provide additional useful thermal and/or mechanical energy. A CHP unit can also be configured as a "bottoming cycle" unit. In a bottoming cycle CHP unit, fuel is first used to provide thermal energy for an industrial process and the waste heat from that process is then used to generate electricity. Some WHP units are also bottoming cycle units and the accounting treatment for bottoming cycle CHP units is provided with the WHP description below.

[142] The applicable CO_2 emission limit rate depends on the type of state plan being implemented. Where a state plan includes a single CO_2 emission limit rate for the fleet of affected EGUs, the applicable rate is the rate that applies to all affected EGUs. Where a state plan includes subcategorized rates for different categories of affected EGUs, the applicable rate is the rate that applies to affected NGCC EGUs.

would be limited to values between 0 and 1.

Prorated MWh = (1 - incremental CHP emission rate/applicable affected EGU emission limit rate) * CHP MWh output

Where the ratio is limited to values between 0 and 1.

The CHP electrical emission rate is the net emission rate when the CHP unit's thermal output emissions are deducted from the CHP unit's total emissions. It can be derived as follows

[CHP fuel input * fuel emission factor – (UTO/boiler efficiency) * fuel emission factor]/CHP MWh

Non-affected CHP units can use qualifying biomass fuels. As described in Section VIII.G.1.a.(2)(c), states should propose qualifying biomass feedstocks and treatment of biogenic CO_2 emissions in state plans, along with supporting analysis and quality control measures, and the EPA would review the appropriateness and basis for such determinations in the course of its review of a state plan. Considerations for qualifying biomass included in state plans are discussed in section VIII.G.1.a.(2).(c).(i).

The measurement of the fuel and MWh output of the CHP unit are based on standard industry practice and discussed in section VIII.G.d.5.

In order to determine the incremental CO_2 emission rate, a CHP unit would monitor requirements for CO_2 emissions and energy output.[143] The monitoring requirements are standard methods

[143] Where a CHP unit uses biomass fuel, it must report both total

currently in use and the requirements would depend on the size of the CHP units and the fuel used in the unit.

Non-affected CHP facilities[144] with electric generating capacity greater than 100 MW would follow the same monitoring and reporting protocols for CO_2 emissions and energy output as are required for affected EGU CHP units. These requirements are discussed in section VIII.F. For non-affected CHP facilities with electric generating capacity less than 100 MW, which use only natural gas and/or distillate fuel oil, the low mass emission unit CO_2 emission monitoring and reporting methodology outlined in 40 CFR 75, or a similar fuel tracking and emission factor approach, is acceptable. For non-affected CHP facilities with an electric generating capacity less than 100 MW, which use all other fuels, the CO_2 emissions monitoring and reporting protocols for affected EGU CHP units would be used. These requirements are discussed in section VIII.G.5.

Most comments received on CHP recommended that the EPA explicitly call out how CHP can be accounted for in a state plan. Some commenters pointed out that without such a description, states would not be able to readily take advantage of the CO_2 emissions reduced by the use of CHP. Other commenters weighed the advantages to considering a numerator-based approach versus a

CO_2 emissions and biogenic CO_2 emissions. Requirements for reporting biogenic CO_2 emissions are discussed in section VIII.G.1.a.(2)(c) above.

[144] A CHP facility may consist of one or more electric generators.

denominator-based approach. The EPA believes that a denominator approach is appropriate because it is consistent with the accounting approach used for RE and demand-side EE.

(10) WHP. WHP units that meet the eligibility criteria under section VIII.G.1.b.(2) may be used to adjust the CO_2 emission rate of an affected EGU. There are several types of WHP units. There are units, also referred to as bottoming cycle CHP units, where the fuel is first used to provide thermal energy for an industrial process and the waste heat from that process is then used to generate electricity.[145] Emissions from these WHP facilities would be based on the initial fuel combustion process that produced the waste heat and would be accounted in the same way as non-affected CHP units under section VIII.G.1.b.9.

There are WHP facilities where the waste heat from the initial combustion process is used to generate additional power. There is no additional fuel used to generate this additional power as so there are no incremental emissions associated with that additional power. As a result, the incremental electric generation output from the WHP facilities could be considered non-emitting and the MWh of electrical output used to adjust the CO_2 emission rate of an affected EGU.

Most commenters noted the benefits for WHP at the same time

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[145] This configuration is sometimes referred to as a "bottoming cycle" CHP unit. In such a configuration, the waste heat stream could also be generated from a mechanical process, such as at natural gas pipeline compressors.

they discussed the benefits of CHP. The commenters reflected that WHP is another compliance option and requested it be called out explicitly as a compliance option. The comments discussed WHP benefits but did not elaborate on a preferred accounting method.

b. Measures that may not be used to adjust a CO_2 emission rate.

This section addresses measures that may not be used to adjust a CO_2 emission rate. Other new and existing non-affected fossil fuel-fired EGUs that are not subject to CAA section 111(b) or 111(d) may not be used to adjust the CO_2 emission rate of an affected EGU. While generation from such units could substitute for generation from affected EGUs, the EPA has determined that additional incentives for such generation, in the form of an explicit adjustment to the CO_2 rate of an affected EGU, are not necessary or warranted. Providing for such an adjustment could create perverse incentives for the construction of new simple cycle CTs that are not subject to the applicability criteria of final Standards of Performance for Greenhouse Gas Emissions from New Stationary Sources: Electric Utility Generating Units rule. For example, such units could provide only limited adjustment credit, as operation beyond a certain capacity factor threshold would trigger applicability under CAA section 111(b). Further, providing for the ability to generate adjustment credits would provide incentives for construction of less efficient fossil generating capacity than would likely otherwise be constructed (e.g., addition of a simple cycle combustion turbine rather than a NGCC unit). In addition, providing for the ability to generate adjustment credits could create perverse incentives for the continued operation of less efficient existing fossil generating capacity. Such outcomes run counter to the objectives of this final rule.

c. Measures that reduce CO_2 emissions outside the electric power sector. Measures that reduce CO_2 emissions outside the electric power sector may not be counted toward meeting a CO_2 emission performance level for affected EGUs or a state CO_2 goal, under either a rate-based or mass-based approach, because all of the emission reduction measures included in the EPA's determination of the BSER reduce CO_2 emissions from affected EGUs. Examples of measure that may not be counted toward meeting a CO_2 emission performance level for affected EGUs or a state CO_2 goal include GHG offset projects representing emission reductions that occur in the forestry and agriculture sectors,[146] direct air capture, and crediting of CO_2 emission reductions that occur in the transportation sector as a result of vehicle electrification.

3. Requirements for rate-based emission trading approaches

[146] We note, however, that the final emission guidelines allow state measures like emission budget trading programs to include out-of-sector GHG offsets. For example, both the California and RGGI programs allow for the use of allowances awarded to GHG offset projects to be used to meet a specified portion of an affected emission source's compliance obligation. The RGGI program contains a cost containment allowance reserve that makes available additional allowances up to a certain amount, at specified allowance price triggers. See section VIII.C.3.b(2)(a) of this preamble.

As with all approaches under the emission standards plan type, emission standards in a state plan that include a rate-based emission trading program must be quantifiable, verifiable, enforceable, non-duplicative and permanent.[147] A state plan using a rate-based emission trading approach must include rate-based emission standards for affected EGUs along with related implementation and compliance requirements and mechanisms.[148] These related requirements include those applicable to rate-based emission standards more broadly: CO_2 emission monitoring, reporting, and recordkeeping requirements for affected EGUs, including requirements for monitoring and reporting of useful energy output. Related requirements for a rate-based emission trading program more specifically include provisions for issuance of ERCs by the state and/or its designated agent; provisions for tracking ERCs, from issuance through submission for compliance; and the administrative process for submission of ERCs by the owner or operator of an affected EGU to the state, in order to adjust its reported CO_2 emission rate when demonstrating compliance with a rate-based emission standard.[149] These requirements specific to rate-based emission trading programs are design elements the EPA has determined are necessary to assure

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[147] These requirements are described in detail in section VIII.D.2.

[148] As described below, these requirements would likely be provided in a state plan in the form of state regulations, but could potentially be provided in another form.

[149] See section VIII.G.1 for a discussion of the accounting method used to adjust a CO_2 emission rate.

the integrity of a rate-based approach that includes an emission trading program, and therefore assures a state plan utilizing such an approach appropriately provides for the implementation of rate-based emission standards in accordance with CAA section 111(d).

The EPA will review a state plan submittal including a rate-based emission trading program to assure that the plan contains the design elements necessary to assure the integrity of a rate-based approach, and therefore provide for the implementation of rate-based emission standards. These design elements are discussed in more detail in this subsection, and the EPA for each design element has also provided what it views as an appropriate way for states to meet each such element so as to provide for the implementation of rate-based emission standards through an emission trading program. The EPA expects that state plans containing a rate-based emission trading program that includes components as substantively described for each of the design elements will be presumptively approvable (so long as the rest of the plan satisfactorily addresses all other requirements, including that the rate-based emission standards are appropriately demonstrated to achieve the CO_2 emission performance rates or state CO_2 goal). States may submit a rate-based emission trading program with alternative components other than those described, so long as the program includes each of the required design elements and the state satisfactorily demonstrates in the state plan submittal that such alternative means of addressing the design elements are as stringent in all respects as the presumptively approvable approach as described, and therefore provide for the implementation of the state plan's rate-based emission standards.

The EPA also notes it is proposing model rules for both mass-based and rate-based emission trading programs. States that adopt and submit the finalized model rules for the rate-based trading program will be presumptively approvable as meeting the requirements of CAA section 111(d) and these emission guidelines.

A state may issue ERCs to an affected EGU that performs at a CO_2 emission rate below a specified CO_2 emission rate, as well as to providers of qualifying measures that provide substitute generation for affected EGUs or avoid the need for generation from affected EGUs. This latter category includes providers of qualifying RE and demand-side EE measures, as well as other types of measures, as discussed in section VIII.G.1.b.[150]

ERCs may be used by an affected EGU to adjust its reported CO_2 emission rate when demonstrating compliance with a rate-based emission limit. This adjustment is made by adding MWh to the denominator of an affected EGU's reported CO_2 emission rate, in

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[150] As used in this section, the term "EE program" refers to an EE deployment program. An EE program involves deployment of multiple EE measures or EE projects, such as utility- or state-administered EE incentive programs that accelerate the deployment of EE technologies and practices. As used in this section, the term "EE/RE project" refers to a discrete EE project (e.g., an EE upgrade to a commercial building or set of buildings) or a RE generator (e.g., a single wind turbine or group of turbines).

the amount of submitted ERCs, resulting in a lower adjusted rate. To demonstrate compliance with a rate-based emission standard, an affected EGU would report its CO_2 lb/MWh emission rate to the state regulatory body, and would also surrender to the state any ERCs it wishes to use to adjust its reported emission rate. The state regulator would then cancel the submitted ERCs and add the MWh the ERCs represent to the denominator of the affected EGU's reported CO_2 lb/MWh emission rate. If the affected EGU's adjusted CO_2 emission rate is equal to or lower than its applicable emission rate standard, the affected EGU would be in compliance.

a. Issuance of ERCs to affected EGUs. ERCs may be issued to affected EGUs that emit below a specified CO_2 emission rate. For issuance of ERCs to affected EGUs, the state plan must specify the accounting method and administrative process for ERC issuance. This includes the calculation method for determining the number of ERCs to be issued to an affected EGU, based on reported CO_2 emissions and MWh energy output, in comparison to a reference CO_2 emission rate. The reference rate is a specified CO_2 lb/MWh emission rate that an affected EGU's reported CO_2 emission rate is compared to, when determining the amount of ERCs that may be issued to an affected EGU.

Following determination of the number of ERCs an affected EGU is eligible to receive, based on an affected EGU's reported CO_2 emission rate compared to a specified reference rate, the state regulatory body would issue those ERCs into a tracking system account held by the owner or operator of the affected EGU. Tracking system requirements are addressed below at section VIII.G.3.c.

The accounting method that may be applied in a state plan differs depending on whether a state plan includes a single rate-based emission standard that applies to all affected EGUs (e.g., if a plan is designed to meet a state rate-based CO_2 goal) or separate rate-based emission standards that apply to subcategories of affected EGUs, namely fossil fuel-fired electric utility steam generating units and stationary combustion turbines. In both cases, ERCs are issued in MWh, based on the difference between an affected EGU's reported CO_2 emission rate (in CO_2 lb/MWh) and a specified CO_2 lb/MWh emission rate that the reported rate is compared to (referred to as a "reference rate"). The reference rate may be an affected EGU's assigned CO_2 emission limit rate or another CO_2 emission rate, as described below. Where an affected EGU's reported CO_2 emission rate is lower than the specified reference CO_2 emission rate, ERCs may be issued.

Where a state plan includes emission standards in the form of a single rate-based emission standard that applies to all affected EGUs, the reference rate is the CO_2 emission rate limit for affected EGUs. In this instance, ERCs may be issued based on an affected EGU's reported CO_2 emission rate as a proportion of the emission limit rate. For example, if the emission rate limit is 2,000 lb CO_2/MWh and the affected EGU emits at a rate of 1,000 lb CO_2/MWh, 0.5 MWh of ERCs would be awarded for every MWh generated by the affected EGU. ERCs would be issued to affected EGUs in whole MWh increments. The calculation method is as follows:

ERCs[151] = reported MWh by affected EGU[152] x ((CO_2 emission rate limit for affected EGUs[153] - affected EGU reported CO_2 emission rate[154])/ CO_2 emission rate limit for affected EGUs)

For the example above, the calculation is as follows:

ERCs = MWh reported x (2,000 - 1,000)/2,000 = MWh reported x 0.5

If the affected EGU in this example generated 1,000,000 MWh, 500,000 ERCs would be issued.

Where a state plan includes separate emission standards for subcategories of affected EGUs, specifically affected fossil fuel-fired electric utility steam generating units and stationary combustion turbines, the reference rate differs for affected fossil fuel-fired electric utility steam generating units and stationary combustion turbines.

For affected steam generating units, the reference CO_2 emission rate is the assigned CO_2 emission rate limit for steam generating units.

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151 For all calculations in this section, where the result is a negative value, no ERCs would be issued.

152 This term represents the reported MWh by the affected EGU on an annual basis.

153 This term represents the "reference rate."

154 This term represents the annual reported CO_2 emission rate of the affected EGU.

For affected steam generating units, the following accounting method for generating ERCs applies:

ERCs[155] = reported MWh x ((steam generating unit CO_2 emission rate limit[156] – steam generating unit reported CO_2 emission rate)/ steam generating unit CO_2 emission rate limit).

For affected stationary combustion turbines, the reference CO_2 emission rate differs for "non-incremental" generation and "incremental" generation from the affected stationary combustion turbine. Incremental generation by an affected EGU is defined as annual energy generation, in MWh, that is greater than reported MWh generation by the EGU in 2012. For example, assume an affected stationary combustion turbine generated 1,000,000 MWh in 2012 and 1,100,000 MWh in 2022; the stationary combustion turbine's incremental generation in 2022 is 100,000 MWh and its non-incremental generation is 1,000,000 MWh.

For affected stationary combustion turbines, the following accounting method for generating ERCs applies for *non-incremental* generation:

ERCs = reported MWh x ((stationary combustion turbine CO_2 emission rate limit[157] – stationary combustion turbine reported CO_2 emission rate)/ stationary combustion turbine CO_2 emission rate limit)

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[155] For all calculations in this section, where the result is a negative value, no ERCs would be issued.
[156] The "reference rate."
[157] The "reference rate."

Under this approach, ERC issuance is assessed based on the difference between the CO_2 emission rate limit for affected stationary combustion turbines[158] and the reported CO_2 emission rate of the affected stationary combustion turbine. In other words, affected stationary combustion turbines earn ERCs for non-incremental generation when they perform at an emission rate better than the reference rate for stationary combustion turbines, similarly to how affected steam units can earn ERCs.

In addition, affected stationary combustion turbines can also earn ERCs for incremental generation that reflects the replacement of steam unit generation by generation from the stationary combustion turbine. For affected stationary combustion turbines, the following accounting method for generating ERCs applies for *incremental* generation:

ERCs = reported MWh x [((steam generating unit CO_2 emission rate limit[159] – stationary combustion turbine reported CO_2 emission rate)/ steam generating unit CO_2 emission rate limit) + ((stationary combustion turbine CO_2 emission rate limit[160] – stationary combustion turbine reported CO_2 emission rate)/ stationary combustion turbine CO_2 emission rate limit)]

Under this approach, ERC issuance is assessed based in part on the difference between the CO_2 emission performance level for

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158 This is the CO_2 emission performance level for affected stationary combustion turbines in the emission guidelines.
159 The "reference rate."
160 The "reference rate."

fossil steam generating units and the reported CO_2 emission rate of the affected stationary combustion turbine. The calculation also accounts for the difference in an affected stationary combustion turbine's reported CO_2 emission rate and the CO_2 rate limit for affected stationary combustion turbines.[161] This avoids over-crediting where an affected stationary combustion turbine emits above its assigned CO_2 emission rate limit. Overall, this calculation method allows for issuance of ERCs based on the ability of incremental generation from affected stationary combustion turbines to substitute for generation from affected steam generating units (as represented in building block 2), while also respecting the fact that affected stationary combustion turbines must also meet an assigned CO_2 emission rate limit for the entirety of its MWh energy output.

For example, assume an affected stationary combustion turbine with a CO_2 emission rate of 800 lb CO_2/MWh; a stationary combustion turbine CO_2 emission rate limit of 700 lb CO_2/MWh; and a steam generating unit CO_2 emission rate limit of 1,300 lb CO_2/MWh. For every incremental MWh of reported energy generation by an affected stationary combustion turbine, ERCs would be issued in the following amount:

ERCs = reported incremental MWh x [(1,300 - 800)/1,300 + (700 - 800)/700] = reported incremental MWh x [0.38 + (-0.14)] =

[161] This is the CO_2 emission performance level for affected stationary combustion turbines in the emission guidelines.

reported MWh x 0.24[162]

Thus, for every incremental MWh of reported energy generation by an affected stationary combustion turbine, 0.24 ERCs would be generated. ERCs would be issued in whole MWh increments.

These accounting requirements maintain consistency with the EPA's application of BSER when calculating CO_2 emission performance rates for affected stationary combustion turbine and steam generating units. In particular, this accounting treatment maintains consistency of accounting in a state rate-based CO_2 emission standard with the EPA's application of building block 2 in calculating CO_2 emission performance rates for affected fossil fuel-fired electric utility steam generating units and stationary combustion turbines, which is based on use of incremental generation from affected stationary combustion turbine to replace generation from affected steam generating units.

b. Issuance of ERCs for RE, demand-side EE, and other measures. ERCs may be issued for qualifying measures.[163] For issuance of

[162] This calculation accounts for incremental generation from the affected stationary combustion turbine, while acknowledging that stationary combustion turbine generation is low-emitting, but not non-emitting. The calculation also acknowledges that in this instance, the affected stationary combustion turbine's reported CO_2 emission rate is higher than its applicable emission rate limit. As a result, for every MWh of generation, the stationary combustion turbine accrues a compliance debit that must be met through submission of ERCs. This calculation avoids over-crediting for incremental generation by affected stationary combustion turbines, where an affected stationary combustion turbine emits above its assigned CO_2 emission rate limit.

[163] Qualifying measures that can be used to adjust the CO_2

ERCs for qualifying measures, state plan requirements for ERC issuance must include a two-step process. In the first step of the process, a potential ERC provider submits an eligibility application for a qualifying program or project[164] to the administering state regulator (or its agent[165]). The state regulator reviews the application to determine whether, in this example, an EE/RE program or project meets eligibility requirements for the issuance of ERCs.[166] An eligibility application must include a description of the program or project, a projection of the MWh generation or energy savings anticipated over the life of the program or project, and an EM&V plan that meets state requirements. The EM&V plan must describe how MWh of RE generation or energy savings resulting from the program or

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emission rate of an affected EGU are discussed at subsection VIII.G.1, and include RE, demand-side EE, and other measures, such as DSM, CHP and incremental nuclear generation.

[164] For example, for an EE/RE program or project, as described in this section for illustrative purposes. The requirements described in this section for EE/RE programs and projects also apply for all other eligible qualifying measures discussed in subsection VIII.G.1.

[165] As used here, an agent is a party acting on behalf of the state, based on authority vested in it by the state, pursuant to the legal authority of the state. A state could designate an agent to provide certain limited administrative services, or could choose to vest an agent with greater authority. Where an agent issues an ERC on behalf of the state, such issuance would have the same legal effect as issuance of an ERC by the state.

[166] The entity implementing the EE/RE program or project (referred to in the preamble as a "provider") would submit the application. This is the identified entity to which ERCs would ultimately be issued, to a tracking system account held by the entity. Such entities could include a wide variety of parties that implement EE/RE programs and projects, including owners or operators of affected EGUs, electric distribution companies, independent power producers, energy service companies, and administrators of state EE programs, among others.

project will be quantified and verified.[167] A state, in its emission standard regulations, must include requirements for EM&V plans that are consistent with the requirements in the emission guidelines for EE/RE measures and other eligible measures, as discussed in section VIII.G.1 above, and section VIII.C.4 below.

The EPA has determined that state requirements for an eligibility application must include review of the application by an accredited independent verifier prior to submittal. This requirement builds on the approach used for assessing GHG offset projects, both in international emission trading programs and the GHG emission budget trading programs implemented by California and the RGGI participating states.[168] An assessment by an accredited independent verifier would be included as a component of an eligibility application.

The EPA has determined that independent verification requirements are necessary to ensure the integrity of state rate-based emission trading programs included in a state plan, given the wide range of eligible measures that may generate ERCs and

[167] The verification process includes confirmation that quantified MWh are non-duplicative and permanent (i.e., are not being used in any other state plan to demonstrate compliance with an emission standard or achievement of a state CO_2 goal).

[168] Information about the verification process for GHG offsets under the RGGI program, including verifier accreditation requirements and access to relevant documents, is available at http://www.rggi.org/market/offsets/verification. Similar information about the verification process for GHG offsets under the California program is available at http://www.arb.ca.gov/cc/capandtrade/offsets/verification/verification.htm.

the broad geographic locations in which those measures may occur. Inclusion of an independent verification component provides technical support for state regulatory bodies to ensure that eligibility applications and monitoring and v/erification reports are thoroughly reviewed prior to issuance of ERCs.

Rate-based emission trading programs used in a state plan must include requirements for independent verifiers that specify necessary qualifications and codes of conduct when providing verification services. State requirements must include accreditation requirements for independent verifiers that specify that only accredited verifiers may provide verification services and detail the requirements for accreditation and maintenance of accreditation status.[169]

These requirements must ensure that verifiers have sufficient knowledge of the rate-based emission trading program rules, technical expertise, and knowledge of auditing, accounting, and information management practices. Accredited verifiers must be independent. Accredited verifiers may not provide verification services for any ERC provider for which they have a financial, management, or other interest.[170] Such

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[169] In this subsection, the term "verifier" is used interchangeably to refer to both a "verification body" (i.e., a verification company or organization) and a "verifier," which is an individual that is a principal or employee of a verification body.

[170] Accredited verification bodies and individual verifiers may not have any direct or indirect organizational or personal relationships with an ERC provider that would impact their impartiality in assessing the validity and accuracy of the

relationships constitute a conflict of interest (COI). COI situations may also arise as a result of personal relationships among individuals representing an ERC provider and an accredited verifier. State requirements must specify that a verification report will not be accepted as part of an eligibility application or M&V report where the accredited verification body or any individual verifier has a COI. Accredited verification bodies must have management protocols in place to identify and remedy any COI prior to provision of verification services. State requirements should specify that failure of an accredited verifier to identify and adequately address any COI prior to provision of verification services is grounds for revocation of accreditation. State accreditation requirements should include periodic performance reviews by the administering state regulatory body of accredited verifiers, to ensure that verifiers are maintaining necessary technical and professional qualifications and are meeting program requirements for provision of verification services. State accreditation requirements may recognize in part accreditation by an outside organization other than the state, where such outside accreditation demonstrates that certain state requirements are met.[171]

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information in an eligibility application or M&V report. In addition to this general requirement, the following specific requirements also apply. Accredited verifiers must have no direct or indirect financial interest in, or other financial relationships with, an ERC provider or any related program or project that seeks issuance of ERCs. Accredited verifiers must have no relationship with the implementer of a program or project that seeks the issuance of ERCs, or any related ERC provider, that would represent a COI. Accredited verifiers must have no role in the development and implementation of a program or project that seeks issuance of ERCs, beyond the provision of verification services. Accredited verifiers must not be compensated, directly or indirectly, in relation to the quantified and verified MWh in an M&V report or on the basis of program or project approval, ERC issuance, or the number of ERCs issued. Accredited verifiers may not hold ERCs, or other financial derivatives related to ERCs, or have a financial relationship with other parties that hold ERCs or other related financial derivatives. Verification reports must include an attestation by the accredited verifier that it assessed potential COI related to an ERC provider and adequately addressed any identified COI.

[171] An example is ANSI accreditation under ISO 14065:2013 for GHG validation and verification bodies. More information is available

The state's eligibility requirements and application procedures must ensure that only eligible actions may generate ERCs and that documentation is submitted only once for each program or project, and to only one state program.[172] These provisions will ensure that actions that are eligible for the issuance of ERCs are "non-duplicative."[173] The tracking system used to administer a state's rate-based emission trading system must provide transparent, electronic, public access to information about program and project eligibility applications, including EM&V plans, and regulatory approval status.

In the second step of the process, following implementation of the RE/EE program or project, in this example, that was approved in step one, the RE/EE provider periodically submits a monitoring and verification (M&V) report to the state regulatory body documenting the results of the program or project in MWh of electric generation or energy savings.[174] These results are quantified according to the EM&V plan that was approved as part of step one. These results are verified by an accredited independent verifier, and its verification assessment must be

at https://www.ansica.org/wwwversion2/outside/GHGgeneral.asp?menuID=200.

[172] This includes ensuring that multiple parties do not submit an eligibility application for the same EE program or project, or for the same RE generator.

[173] Emission standards must be "non-duplicative" as described in section VIII.D.2.

[174] State rate-based emission trading program regulations should specify the frequency for submission of monitoring and verification reports for approved qualified measures that have been deemed eligible to generate ERCs.

included as part of the M&V report submitted to the state regulatory body. The administering state regulator (or its agent) then reviews the M&V report, and determines the number of ERCs (if any) that should be issued, based on the report. Finally, the state regulatory body (or its agent) issues ERCs to the provider of the approved program or project. These ERCs are issued to the tracking system account held by the program or project provider.

State requirements must ensure that only one ERC is issued for each verified MWh. This is addressed through registration in the tracking system of programs and projects that have been qualified for the issuance of ERCs, to ensure that documentation is submitted only once for each RE/EE action, and to only one state program.[175] The tracking system must provide transparent electronic public access to submitted M&V reports and regulatory approvals related to such reports.[176] Such reports are the basis for issuance of ERCs.

c. Tracking system requirements. State requirements must include provisions to ensure that ERCs issued to any eligible entity are properly tracked from issuance to submission by affected EGUs for compliance (where ERCs are "surrendered" by the owner or operator of an affected EGU and "retired" or "cancelled" by the administering state regulatory body), to ensure they are only

[175] EE/RE programs and projects, and other eligible measures, with an approved eligibility application would be designated in a tracking system as qualified programs or projects. Qualified programs and projects may be issued ERCs, based on approved M&V reports.

[176] This must include electronic Internet access to such information in the tracking system.

used once to meet a regulatory obligation. This is addressed through specified requirements for tracking system account holders, ERC issuance, ERC transfers among accounts, compliance true-up for affected EGUs,[177] and an accompanying tracking system infrastructure design based on business rules specified in the emission trading program regulations. Each issued ERC must have a unique identifier (e.g., serial number) and the tracking system must provide for traceability of issued ERCs back to the program or project for which they were issued.

The EPA received a number of comments from states and stakeholders about the value of the EPA's support in developing and/or administering tracking systems to support state administration of rate-based emission trading systems. This could include regional systems and/or a national system. The EPA is exploring options for providing such support and is conducting an initial scoping assessment of tracking system support needs and functionality.

d. Effect of improperly issued ERCs: Because the goal of this rulemaking is the actual reduction of CO_2 emissions, it is fundamental that ERCs represent the MWh of energy generation or savings they purport to represent. To this end, only valid ERCs that actually meet the standards articulated in this rule may be used to satisfy any aspect of compliance by an affected EGU with

[177] "Compliance true-up" refers to ERC submission by an owner or operator of an affected EGU to adjust a reported CO_2 emission rate, and determination of whether the adjusted rate is equal to or lower than the applicable rate-based emission limit.

emission standards. Despite safeguards included in the structure of ERC issuance and tracking systems, such as the review of eligibility applications and M&V reports, and state issuance of ERCs, ERCs may be issued that do not, in fact, represent eligible zero-emission MWh as required in the emission guidelines. A variety of situations may result in such improper ERC issuance, ranging from simple paperwork errors to outright fraud.

It is thus essential that the ultimate responsibility for the validity of the ERC rest with the entity that must achieve compliance with an emission standard. An approvable state plan that allows affected EGUs to comply with their emission standards in part through reliance on ERCs must include provisions making clear that an affected EGU may only use properly issued, valid ERCs to demonstrate compliance with its emission standard. An EGU that submits for compliance with its emission standard an ERC that does not actually represent an eligible MWh of zero-emission generation is subject to CAA liability for failure to meet its emission standard for each day of the relevant compliance period, and must submit two properly issued, valid replacement ERCs to the state regulatory body within a specified period of time, in accordance with the emission guidelines. This is true regardless of the good faith of the EGU in purchasing or obtaining the ERC. The state plan must also make clear that the EGU is also subject to CAA liability for failure to timely submit replacement ERCs.

e. Considerations for ERC issuance. The EPA notes that state-administered and state-overseen EE programs, such as those administered by state-regulated electric distribution utilities, could play a key role in supplying energy savings to a rate-based emission trading system in the form of ERCs. These programs have been the primary means for delivering EE programs and energy savings at scale, and also allow for a state to conduct a portfolio planning process to guide EE program design and focus in a manner that best provides multiple benefits to electricity ratepayers in a state. Such portfolio planning processes typically treat EE as an energy resource comparable to electricity generation.

The EPA also notes that non-ERC certificates may be issued by states and other bodies for MWh of energy generation and energy savings that are used to meet other state regulatory requirements, such as state RPS and EERS, or by individuals to make environmental or other claims in voluntary markets.

The EPA defines an ERC in the emission guidelines as a tradable compliance instrument that represents a zero-emission MWh from a qualifying measure that may be used to adjust the reported CO_2 emission rate of an affected EGU subject to a rate-based emission standard in an approved state plan under CAA section 111(d). The sole purpose of an ERC is for use by an affected EGU in demonstrating compliance with a rate-based emission standard in such an approved state plan.

An ERC is issued separately from any other instruments that may be issued for a MWh of energy generation or energy savings from a qualifying measure. Such other instruments may be issued for use in meeting other regulatory requirements (e.g., such as state RPS and EERS requirements) or for use in voluntary markets. An ERC may be issued based on the same data and verification requirements used by existing REC and EEC tracking systems for issuance of RECs and EECs.

4. EM&V requirements for RE and demand-side EE resources used to adjust a CO_2 rate

This section identifies and discusses the EM&V criteria used to quantify MWh savings from demand-side EE and generation from zero-emitting RE.[178] These criteria apply in the context of both emission standard plans and state measures plans, as described below. The EPA is finalizing these criteria as applicable requirements in the context of state plans that employ a rate-based emission trading program. These criteria are described below. State plans must require that MWh savings from demand-side EE and generation from zero-emitting RE are quantified per these criteria.[179]

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[178] EM&V is defined to mean the set of procedures, methods, and analytic approaches used to quantify the MWh from demand-side EE and RE, and thereby ensure that the resulting savings and generation are quantifiable and verifiable.

[179] For a rate based emission standards plan type, the requirement to quantify the MWh from demand-side EE and RE per the EM&V criteria must be included in the federally enforceable state plan. For a state measures plan implementing rate based state measures, applicable state laws must reflect the requirement to quantify the MWh from demand-side EE and RE per the EM&V criteria, and such state only requirements must be adequately

Additionally, with respect to these criteria, the EPA describes certain established standard industry practices that would be presumptively approvable as an approach to include these criteria in state plans. States must submit these criteria as specified, or alternatively, states may submit the standard industry practices described as presumptively approvable. States may also submit other means of meeting the criteria so long as the state satisfactorily demonstrates in the state plan submittal that such alternative means of addressing criteria are as adequately stringent as the presumptively approvable approach described here.

As discussed in VIII.G.3, quantified and verified MWh of RE generation, and quantified and verified MWh avoided from implementing demand-side EE measures,[180] may be used to adjust a CO_2 emission rate when demonstrating compliance with the emission guidelines. In states implementing emission standard type plans with rate-based trading, affected EGUs adjust their reported emission rate using ERCs, which represent MWh that are quantified and verified according to the EM&V criteria included in this section. Providers of EE and RE who seek to earn ERCs must

described in the supporting documentation submitted with the state plan.

[180] In the context of demand-side EE, "measure" refers to an installed piece of equipment or system at an end-use energy consumer facility, a strategy intended to affect consumer energy use behaviors, or a modification of equipment, systems or operations that reduces the amount of energy that would otherwise have been used to deliver an equivalent or improved level of end-use service.

develop EM&V plans outlining how they will quantify and verify the results of their efforts. These providers are then required to submit EM&V plans as part of their application to the state regulatory body for project approval.[181]

In states implementing state measures type plans, quantified and verified MWh of RE and EE may be used to adjust an emission rate through two pathways. First, if the state measures plan enables rate-based trading, the affected EGUs may use ERCs to adjust their reported rate (per the rate-based emission standard approach). Alternatively, if the state measures plan elects to incorporate RE and demand-side EE outside of an ERC trading program - for example through adoption and implementation of an EERS or RPS - the state itself, rather than the project provider, uses the quantified and verified MWh of RE and EE to adjust the rate.

If a state elects to implement a rate-based ERC trading program as part of its state measures approach, state regulations and project provider requirements must be identical to those outlined for emission standard plans. For a state measures plan, the ERC issuance and EM&V requirements must be adequately described in the submittal's supporting materials to enable the EPA to determine whether the state measures plan satisfactorily demonstrates the ability of the affected EGUs to meet the applicable CO_2 emission performance rate or state goal. For an

[181] A full discussion of applicable requirements for the establishment and functioning of rate-based emissions trading systems is provided above, at section VIII.G.3.

emission standards plan, the ERC issuance and EM&V requirements would be submitted as a component for approval as part of the federally enforceable state plan. However, if the state elects to incorporate demand-side EE and RE policies, programs, and projects outside of an ERC trading program, the state itself, rather than the project provider, must demonstrate how it will quantify and verify the results of its efforts. In this case, the state must describe in its state plan submission how the criteria described herein will be applied to specific programs and projects to demonstrate that reported annual MWh savings and generation are properly quantified and verified.

The following discussion presents EM&V criteria for demand-side RE and EE measures implemented through both types of state plan approaches, followed by a presentation of some additional considerations for states implementing RE and EE measures in the context of a state measures plan without rate-based trading.

5. EM&V criteria for RE and demand-side EE resources used to adjust a CO_2 rate

The proposed rule stated that the EPA would establish EM&V criteria to help states, sources, and RE and EE providers quantify and verify MWh savings and generation resulting from RE and demand-side EE efforts. The proposal and associated "State Plans Considerations" TSD[182] suggested that the EPA's EM&V

[182] See discussion beginning on p. 34 of the State Plan Considerations TSD for the Clean Power Plan Proposed Rule: http://www2.epa.gov/carbon-pollution-standards/clean-power-plan-proposed-rule-state-plan-considerations.

criteria would leverage the industry-standard practices, protocols, and data-sets currently utilized by the majority of states currently implementing demand-side EE and RE programs. The EPA further noted that many state regulatory bodies and other entities already have significant EM&V infrastructure in place and have been applying, refining and enhancing their evaluation and associated quality assurance approaches for over 30 years. The EPA took comment on whether this infrastructure is appropriate to use as the basis for establishing minimum EM&V criteria for use in rate-based state plans that include RE and demand-side EE. The majority of commenters addressing this question indicated that existing EM&V infrastructure is appropriate to assure quality, credibility, and integrity. Thus, the final EM&V criteria reflected herein are intended to be consistent with and leverage prevailing industry-standard evaluation practices.

In addition, the EPA's final criteria reflect several overarching objectives and principles offered by states, private organizations, and the public during the comment period. One of these is the importance of striking a reasonable balance between EM&V rigor and credibility on the one hand, and the costs associated with performance evaluation on the other. Another objective for the EPA's criteria is to avoid excessive interference with EM&V practices that are already robust, transparent and working well. Therefore, the minimum criteria for EM&V in an approvable state plan establish a floor for EM&V practices to ensure credibility and certainty in savings estimates across jurisdictions.

a. Submittals. Applicable submittals include EM&V plans and EM&V

reports. At the front end of a program or project, EM&V plans are required to document how applicable criteria will be addressed as EM&V is performed over the program or project period. After implementation has occurred, EM&V reports are required to document and describe how each of the criteria was applied on an ex-post basis. These reports also specify the resulting MWh savings or generation values per RE and EE program and project category.

For demand-side EE, EM&V plans and reports for purposes of this final rule are intended to leverage and closely resemble EM&V plans that are already in routine use for a wide range of publicly or rate-payer funded EE programs and energy service company (ESCO) projects. For RE, EM&V plans similarly leverage resources and approaches to tracking systems for RE that are broadly applied. EM&V reports for RE are simply the existing output from these tracking systems.

For all EM&V submittals addressing demand-side EE, the applicable metric is electricity savings, which is defined as a reduction in electricity consumption. EE savings must be determined and reported in units of MWh. The specific procedures and requirements for EM&V submittals in the context of an emission standard plan are outlined above in section VIII.G.3. EM&V submittals for state measures plans are described below.

b. EM&V criteria that apply to all demand-side EE used to adjust an emission rate. The following EM&V criteria apply to all demand-side EE used to adjust an emission rate. They are supplemented by the program and project specific provisions identified below.

(1) Baseline definitions. A critical EM&V issue is the assumptions and approach used to determine baseline energy use. EM&V plans must describe the baselines to be used with clear documentation and discussion of the rationale, applicability, and relevant data sources, protocols, and guidance documents used for defining the baseline.

(2) EM&V methods used to quantify the results of EE projects and programs. This section establishes criteria for the general types of EM&V methods that can EE providers can use to quantify savings from demand-side EE programs and projects that are used to generate ERCs. Consistent with EM&V practices at the state level, where PUCs typically allow utilities and other program administrators to use a range of EM&V methods that reflect applicable circumstances and on-the-ground conditions (versus mandating which methods must be used in a particular situation), the EPA is likewise providing flexibility for RE and EE providers to select from the following broad categories of EM&V methods to determine savings.

Two broad categories of EM&V methods are non-control group approaches such as project-based measurement and verification (M&V),[183] and control group approaches

[183] M&V is the process of using measurements to reliably determine energy and/or demand savings created within an individual facility. The International Performance Measurement and

[184] such as randomized control trials (RCT). Regardless of the approach selected, a key criterion, supported by commenters and consistent with industry-standard practices, is that annual savings values must be determined on a regular basis – at intervals sufficient to credibly document annual savings – by application of one or more of the above-listed EM&V methods. Factors that should be taken into consideration when determining the appropriate interval include the characteristics of subject EE programs, projects, or measures; variability of the savings; the EM&V method used; and the relative scale and magnitude of savings. The EPA expects that EM&V using the above methods will occur at a minimum of four year intervals for building energy codes and product standards; every one, two or three years for different publicly or rate-payer funded EE programs; and annually for large individual commercial and industrial projects. For all demand-side EE used to adjust an emissions rate, the selected method, associated assumptions, and data sources must be identified and described in EM&V plans.

For control group methods, the key EM&V criteria is to follow industry standard protocols and guidelines such as those published by the SEE Action Network and the U.S. DOE's Uniform Methods Protocols (UMP) project. Where feasible, the EPA seeks to

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Verification Protocol (IPMVP) defines four M&V options used in the efficiency industry: two end-use metering approaches, energy use data (billing data) regression analysis, and calibrated computer simulation.

[184] Also referred to as large-scale consumption data analysis.

encourage the use of RCT approaches to establishing control groups, as they involve random selection of comparison groups and are therefore less prone to selection bias.

For M&V methods, the key criteria is that industry-standard protocols and guidelines are followed. These include the IPMVP, protocols published by the Federal Energy Management Program (FEMP), the American Society of Heating, Refrigeration and Air-Conditioning Engineers (ASHRAE), and the U.S. DOE's UMP.

(3) <u>Key considerations for quantifying savings</u>. Regardless of the approach used to quantify and verify MWh savings, EM&V plans must describe how they will address the following key considerations for quantifying savings:

- How major changes in independent variable conditions (weather, occupancy, production rates, etc.) that affect energy consumption and savings estimates will be analyzed. The effects of these changes can be calculated using either real-time conditions or normalized conditions that are reasonably expected to occur throughout the lifetime of the EE project or measure.
- How the initial installation of EE will be verified for EE program categories that involve the installation of identifiable measures (e.g., most publicly or rate-payer funded EE programs and project-based EE evaluated site-by-site and CHP, but not programs that provide customers

with information). A key criterion is that verification[185] is required within the first year of program implementation. All verification activities must be performed using industry-standard techniques (e.g., phone or mail surveys, document review, site inspections, spot or short-term metering). For projects implemented as part of a program, verification can be performed using a sample of projects to represent the full program population. In these cases, sample sizes should be defined per the rigor criteria described herein.

- How avoided T&D systems losses will be included in EE savings values. Demand-side EE programs (other than T&D efficiency measures such as CVR and volt/VAR optimization[186]) may adjust reported savings by using a T&D adder that is based on the lesser of 6 percent[187] of the site-level savings or the calculated statewide annual average T&D loss rate [estimated losses in MWh/(total electric supply - direct electricity use)][188] expressed as

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[185] Verification is an independent assessment to ensure that the EE measures have been installed correctly and have the potential to generate the predicted savings. Verification may also include assessment of baseline conditions and confirmation that the EE measures are operating correctly per their design intent.
[186] More information about these technologies is in section VIII.F.1 above.
[187] 6 percent is the national average losses from 1990-2012 (See: http://www.eia.gov/tools/faqs/faq.cfm?id=105&t=3).
[188] Estimated losses in MWh, total electric supply, and direct electricity use values are available in the U.S. EIA's State Electricity Profiles. See table on Supply and Disposition of Electricity (currently Table 10). Direct electricity use refers

a percentage and based on values in the most recent year and published US EIA State Electricity Profile. Since T&D efficiency measures such as CVR and volt/VAR may reduce both end-use consumption and line losses, MWh savings from T&D measures must be calculated on the basis of procedures identified in an EM&V plan.

- How the duration of EE program or project electricity savings will be determined using annual verification assessments, industry-standard persistence studies, deemed estimates of effective useful life (EUL), or a combination of all three. If deemed EUL estimates are used for determining the duration of savings, then zero savings must be assumed at the end of a program, project, or measure life. If project or program persistence studies are conducted at least every 5 years to determine the duration of savings, then savings can be counted as long as the verification activities indicate continued measure operation and performance.
- How the rigor[189] of quantifying MWh savings values will be assessed, and the methods used to control the types of bias or error relevant inherent to the applied EM&V techniques. Rigor can be quantified using statistical

to the electricity generated at facilities that is not put onto the electricity grid, and therefore does not contribute to T&D losses.

[189] Rigor refers to the level of effort expended to minimize uncertainty from factors such as sampling error and bias. The higher the level of rigor, the more confident one is that the results of the EM&V activities are both accurate and precise.

indicators such as confidence and precision (for annual MWh savings, or for a representative sample of an EE program population), together with a written discussion of the EM&V approaches used, potential risks and biases, and related quality control measures that will be utilized. Sampling of populations is appropriate, provided that (a) the population estimates derived from sampling achieve industry-standard levels of precision and confidence (actual, not ex-ante values), and (b) applicable protocols and guidance documents are applied and cited.

- How double counting will be avoided through the use of tracking and accounting procedures to ensure that two or more programs do not separately claim savings from the same EE project or measure (for example, two EGUs claiming savings from the same lighting retrofit). Other types of double counting must likewise be considered and avoided.

(4) Use of EE EM&V protocols. A separate aspect of industry-standard EM&V practice addressed in the rule proposal is the use of one or more EM&V protocols, guidelines, and guidance. These resources serve to document the EM&V approaches listed above and provide instruction on their application in the field. In public comments, the EPA heard overwhelmingly that such protocols, guidelines, and guidance documents are currently in wide use, and that this use should be continued and encouraged in the context of state plans. The agency agrees with this observation and therefore supports their application in the context of demand-

side EE used to adjust an emission rate. The primary criteria are that EM&V plans must include a clear description and documentation of how the relevant protocols, guidelines, and guidance documents will be applied, as well as after-the-fact documentation in EM&V reports of how they were actually applied.

c. <u>Eligible demand-side EE programs and projects</u>. During the comment period, the EPA received many requests from commenters for explicit consideration of the broad range of demand-side EE programs and projects that are currently being implemented by states and other entities across the country. Specifically, these commenters expressed interest in counting the resulting quantified and verified MWh savings towards the achievement of CO_2 emission rate goals. Consistent with these perspectives, the EPA position is that any demand-side EE program and project that results in MWh savings is potentially eligible, provided that it meets the criteria for eligibility described in section VIII.G.1., and that supporting EM&V is rigorous, complete and consistent with the criteria provided in the emission guidelines and the state plan.

Common demand-side EE programs and project types include:

- Publicly or rate-payer funded customer-funded demand-side management programs
- Project-based EE evaluated site-by-site, for example those implemented by ESCOs at commercial buildings and

industrial facilities

- State and local government building energy code and compliance programs
- State and local government incremental product energy standards

A related technology that is eligible to generate MWh that can be counted towards a rate-based goal is CHP (more information about the eligibility and EM&V criteria for CHP is provided in section VIII.G.1.).

The EPA recognizes that the programs and policies listed above will evolve and change over the rule period, as new technologies emerge and efficiency improves. The agency also expects that new EE program types will emerge and expand throughout the rule period, and that MWh savings resulting from these programs can similarly be considered if quantified and verified according to EM&V criteria specified in industry-standard protocols and guidance documents, and if documentation provided in EM&V plans and reports is transparent, credible and robust.

d. Demand-side EE program- and project-specific EM&V provisions. In addition to the generally-applicable EM&V criteria specified above, EM&V plans and report submittals must include any additional EM&V information needed to ensure that savings from the previously-listed programs and projects are quantifiable and verifiable. This requirement can be fulfilled by documenting in EM&V plans how industry-standard protocols, guidelines, and guidance documents that are relevant to such programs and projects will be applied on a forward-looking basis, and also by confirming in ex-post EM&V reports that they were, in fact, applied. The protocols, guidelines, and guidance documents that identify these provisions may currently exist, or may be developed during the course of the rule period as programmatic strategies and EM&V evolves.

e. EM&V criteria that apply to non-affected CHP. To calculate a CHP unit's creditable MWh, the electrical output is prorated based on the "incremental CO_2 emission rate" of the CHP unit relative to the applicable CO_2 emission rate for affected EGUs in the state, according to the equation described in section VIII.C.1. The EM&V criteria described in this section apply only to the MWh-output terms of the equation, consistent with the definition of EM&V as applied in this rule. The full set of accounting criteria for CHP is provided in VIII.G.1.

For determining the creditable MWh from CHP, the measured output must be derived either from (1) a revenue quality meter that meets the applicable ANSI C-12 standard or equivalent, which is the typical requirement for settlements with RTO and other control-area operators; or (2) for customer-sited CHP that is interconnected behind the customer meter, a revenue quality meter at the AC output of an inverter, where applicable, that is adjusted to reflect the energy delivered into either the transmission or distribution grid at the generator bus bar.

For small systems, defined as individual CHP units with nameplate capacities below 10 kW where metered data are unavailable, generation output may be determined using either self-reporting of generation values[190] or generation-estimating software. In the latter case, calculations of system output must be based on the CHP unit's capacity, estimated capacity factors, and an assessment of the local conditions that affect generation levels. All such input parameters and assumptions must be clearly described and documented. Regardless of whether self-reporting or generation-estimating software is used, CHP providers can report results without an intermediary provided that EM&V plans describe the rigorous quality control and fraud prevention measures that will be applied.

For small systems, generation output may be determined using either estimating software, algorithms, or self-reporting of generation values. In the latter case, EM&V plans must confirm that rigorous quality control and fraud prevention measures are in place. Small systems are defined as individual CHP units with nameplate capacities below 10 kW where metered data are unavailable. For CHP systems that directly serve on-site end-use

[190] Self-reporting means that the generator-owner can read its own meter and report MWh generated directly to a tracking system, without relying on an independent third party or other representative.

electricity loads, avoided T&D system losses can be assessed as is commonly practiced with demand-side EE. Such calculations must apply the criteria described in section VIII.G.4.(b)(3) above.

f. <u>EM&V criteria that apply to all RE</u>. This section describes the EM&V criteria associated with quantifying electricity generation from eligible RE, and for documenting these criteria in EM&V plans and reports. Consistent with prevailing views expressed in public comments, the EPA's criteria are based on the presumption that the quantification of RE generation can leverage the infrastructure and documentation associated with participation in registries of renewable energy certifications (RECs). These registries typically include well-established procedures for registry operations, safeguards, and documentation, all of which support compliance demonstration with state RPS policies.

The primary metric for all RE is electricity generation, in units of MWh. Measured output must be derived either from (1) a revenue quality meter that meets the applicable ANSI C-12 standard or equivalent, which is the typical requirement for settlements with RTO and other control-area operators; or (2) for customer-sited generators that are interconnected behind the customer meter, a revenue quality meter at the AC output of an inverter, adjusted to reflect the energy delivered into either the transmission or distribution grid at the generator bus bar.

For RE units that are managed by regional transmission operators or other control area operators, metered generation data should be electronically collected by the control area's energy management system, verified through an energy accounting or settlements process, and reported by the control area operator to the REC registry at least monthly.

For RE units that do not go through a control area settlements process, metered data should be read and transmitted to the REC registry by an independent third party on a monthly basis, but at a minimum annually. Such data must be verified for reasonableness by the state or the REC registry.

For small systems, defined as individual RE units with nameplate capacities below 10 kW where metered data are unavailable, generation output may be determined using either self-reporting of generation values or generation-estimating software. In the latter case, calculations of system output must be based on the RE unit's capacity, estimated capacity factors, and an assessment of the local conditions that affect generation levels. All such input parameters and assumptions must be clearly described and documented. In addition, each RE unit must be uniquely identified and recorded in a registry to avoid double counting. Such data must be verified for reasonableness by the state or the REC registry. Regardless of whether self-reporting or generation-estimating software is used, RE providers can report the result to the tracking system without an intermediary provided that EM&V plans describe the rigorous quality control and fraud prevention measures that will be applied.

An additional consideration is that RE generation may be aggregated from multiple generators into a single MWh value for the group, provided the following criteria are met: each RE unit is uniquely identified in a tracking system (to ensure that double counting is avoided), the nameplate capacity of each RE unit is less than 150 kW, the aggregated RE units collectively have nameplate generating capacities less than 1.0 MW, the RE units being aggregated utilize the same technology/fuel type, and the RE unit's generation data are based on the same metering or the same generation estimating software or algorithms.

An additional criterion that applies to distributed RE units that directly serve on-site end-use electricity loads is that avoided T&D system losses can be considered, as is commonly practiced with demand-side EE. Such calculations must apply the criteria specified for demand-side EE, as described in section VIII.G.4.(b)(3) above.

g. Additional considerations for EM&V of RE and EE included in state measures type plans. As discussed in the introduction to this section, states implementing state measures type plans may use quantified and verified MWh of EE savings and RE generation to adjust an emission rate through two pathways. First, if the state measures plan enables rate-based trading, the affected EGUs may use ERCs to adjust their reported rate as applicable under the rate-based emission standard approach. In such cases, a state includes EM&V criteria (consistent with those discussed above) in its state plan requirements governing ERC issuance, trading and retirement. Second, if the state measures plan incorporates RE and demand-side EE policies, programs and projects outside of an ERC trading program – e.g., through adoption of an EERS or a RPS – the state itself, rather than the project provider, applies the quantified and verified MWh to adjust the reported emission rate used to demonstrate compliance with the emission guidelines.

In the case of a state measures plan relying on stand-alone RE and EE measures, a state must submit as part of its state plan a description of the RE and EE measures it intends to implement, as well as a discussion of how it intends to quantify the results of those measures consistent with the EMV criteria described herein. A key component of this discussion is the mechanisms and approaches the state intends apply to ensure that MWh savings and generation are independently and credibly quantified and verified. Such mechanisms and approaches must be consistent with industry-standard practices and functionally equivalent to the provisions for independent verifiers for ERC trading in the context of emission standard plans, as described section VIII.G.3. An additional and related component of the state plan is a forecast of expected RE generation and annual incremental and cumulative EE savings.

For any state measures plan that incorporates demand-side EE and RE outside of an ERC trading program, an additional criterion is that states must report annual incremental and cumulative EE savings and RE generation to the EPA every year.[191] These data should be provided to the EPA in a summary format that documents total MWh savings and generation, and that is specified at the level of major policies, programs and projects.

At state plan check-in intervals with the EPA (in 2025, 2028 and 2030), states must provide the EPA with access to applicable program- and project-level EM&V reports used to compile total MWh savings and generation. EM&V reports must document how EM&V criteria were applied to quantify results.

It should be noted that, in the case of state measures plans that utilize a mass-based allowance trading program to meet their goal, EM&V plans and reports are not required. This is true even if the state is actively implementing RE and demand-side EE programs and projects. This is because the emission effects of RE and EE are accounted for in measured stack emissions.

h. Skill certification standards. Several commenters pointed out that skill certification standards can help to assure quality and credibility of demand-side EE and RE projects. The EPA agrees that in conjunction with other EM&V measures discussed in this section, requiring that workers be certified by either a party aligned with the Department of Energy's (DOE) Better Building Workforce Guidelines and validated by a third party accrediting

[191] Per section VIII.D, states that choose a state measures plan must submit an annual report no later than July 1 following the end of each calendar year in the interim period.

body recognized by DOE, or by an apprenticeship program that is registered with the federal Department of Labor (DOL), Office of Apprenticeship or a state apprenticeship program approved by the DOL, or by another skill certification validated by a third party accrediting body can help to substantiate the authenticity of emission reductions due to demand-side EE and RE. The EPA encourages states to ask for a demonstration that the work is performed by a proficient workforce.

L. Treatment of Interstate Effects

In the June 2014 proposal, the EPA acknowledged that emission reduction measures implemented under a state plan will likely have impacts across state boundaries due to the interstate nature of the electric grid, as is discussed above in section VIII.G. These interactions, herein called interstate effects, may be driven in part due to differences in power sector dynamics across states, including the types of affected EGUs in a state, the availability of eligible non-emitting resources, and the costs of different compliance options and existing policies in states. These state-level characteristics play out across dynamic regional grids that provide electricity across state borders. EGUs are dispatched both within and across state borders and are constantly adjusting behavior in response to generation and electricity demand on the regional grid. Whenever CO_2 emission reduction measures, such as RE or demand-side EE, are implemented, the RE or demand-side EE can affect EGU generation and CO_2 emissions across the regional grid. These dynamics can change across multiple affected EGUs on a minute-to-minute, hour-to-hour, and day-to-day basis as electricity demand changes and different generating resources are dispatched. These dynamics will also change in the long-term, as the generating fleet and load behavior change over a period of years. Interactions among states may be further driven by the plan types (i.e., rate-based or mass-based) and the individual characteristics of the plans that states choose to adopt.

In the context of this complex environment of state policies and interstate grids, commenters expressed concern about the risk of double-counting of measure impacts across states and the potential for distortionary incentives between states that could undermine overall CO_2 emission reductions (i.e., emissions "leakage"). Commenters requested that the EPA ensure that states avoid double-counting when demonstrating achievement of state goals and minimize leakage effects.

The EPA acknowledges that some amount of interstate effects will inevitably be present and unavoidable in the context of this rule and may affect how affected EGUs achieve the applicable CO_2 performance rates or state goals under a state plan. The EPA has incorporated elements into the rule that seek to minimize interstate effects. First, states have the option to adopt multi-state compliance that reflects regional interactions. Second, in the method for rate-based plan compliance, the rule provides a general accounting approach for adjusting a source or state's CO_2

rate that inherently acts to minimize state differences. Third, the final CO_2 performance rates uniformly apply the same standard for affected source sectors across the states and also account for the regional supply of RE available to states. These points are further discussed below.

For both rate-based and mass-based approaches, the rule provides states with the option of creating either multi-state plans or trading-ready plans. Both strategies can be effective in minimizing interstate effects because the regional impacts of emission reduction actions across states contribute to meeting aggregate rate-based or mass-based CO_2 emission goals.

Under all types of state plans, states must ensure that the measures and associated CO_2 emission reductions counted as part of meeting their plan requirements are not duplicative of any measures that are counted by another state. Interstate effects make this more difficult because states may be responsible for the deployment of measures that have effects on generation and emissions beyond the state borders. Depending on how these measures are accounted for, the reductions could be counted by both the state that deployed the measure, and the state that reports a reduction in fossil generation or reported emissions. In this final rule, the general accounting approaches for both mass-based and rate-based plans minimize the risk of double counting.

Mass-based plans rely exclusively on reported stack emissions for determining whether a mass-based CO_2 emission goal is achieved. This means that under a mass-based plan any emission reduction measures that are implemented are automatically accounted for in reduced stack emissions of CO_2 from affected EGUs, which avoids concerns about counting the same mass reductions in two different states.

In a rate-based plan, there needs to be an explicit adjustment of reported CO_2 emission rates from affected EGUs, to reflect the measures that substitute low- or zero-emitting generation or energy savings for affected EGU generation. States with rate-based plans must demonstrate that the RE and demand-side EE that they use to adjust their CO_2 emission rate are non-duplicative. The proposal attempted to address this issue in part by limiting demand-side EE that states could claim to in-state measures. In fact, those in-state measures still have an impact outside of the state and states are restricted from taking credit for all the measures they have put in place that reduce CO_2 emissions. Therefore, the EPA is finalizing a treatment that allows states to count all in-state and out-of-state measures, while addressing interstate effects through the structure of its accounting approach for adjusting the CO_2 emission rate of an affected EGU, detailed in section VIII.C.1 above, used to show that the state has met its obligation under its state plan.

The general accounting approach for adjusting the CO_2 emission rate of an affected EGU inherently accounts for the regional nature of how substitute generation and energy savings will impact affected EGU generation and CO_2 emissions. The following discussions refer to the substituting generation and energy savings in question as RE and demand-side EE, but this method can apply to other non-BSER technologies that substitute for affected EGU generation. The adjusted CO_2 emission rate gives credit to the affected EGU or state for the MWhs of RE and demand-side EE it is responsible for deploying, by allowing those MWhs to be added to the denominator of the CO_2 rate, but makes no adjustment to the numerator. Instead, the numerator reflects reported stack emissions, which will reflect the extent to which RE and demand-side EE reduced the affected EGU's generation and emissions, without needing to account for the state in which the RE or demand-EE originated, or exactly how it impacted the regional grid.

Across states with rate-based plans, the accounting method avoids potential double-counting of both components of a CO_2 emission rate: CO_2 emission reductions and generation. Double-counting of CO_2 emission reductions is prevented because there is no explicit adjustment to the numerator of the reported CO_2 emission rate that could be redundant to CO_2 emission reductions already represented in reported CO_2 emissions from the affected EGU, resulting in double-counting.[192] Double-counting of MWhs in

[192] If a MWh of substitute generation or avoided generation replaced generation at *another* affected EGU, CO_2 emission reductions would be represented in reduced reported CO_2 emissions

the denominator can be avoided because adding the MWh that the affected EGU is responsible for deploying to the denominator is relatively straightforward to quantify and assign, and aligns well with the MWh-denominated trading system described in this final rule. As long as it is assured that the MWhs of RE and demand-side EE are only being claimed by one state, as is outlined in section VIII.C.2, then there is no double-counting of MWh. Therefore, the accounting method avoids double counting of both CO_2 emission reductions and MWhs, the two characteristics of RE and demand-side EE measures that affect CO_2 emission rates.

There may also be interactions between mass-based and rate-based plans regarding counting measures, specifically where measures that provide substitute or avoided generation, such as RE and demand-side EE, are located in a mass-based state and can also be used by a rate-based state in meeting the CO_2 performance rates or state goals. The EPA received comments on this particular issue, and many expressed concerns that this use of mass-based resources in a rate-based state would result in double-counting of emission reductions.

Commenters provided analyses specifying how two states can benefit from the same RE and demand-side EE measures as a result of rate- and mass-based plan interactions. Some commenters considered this double-counting of emission reductions, and requested specific mathematical adjustments of reported generation or CO_2 emissions from affected EGUs under either rate-

from *that* affected EGU. Again, a double-counting of emission reduction effects would occur.

based or mass-based state plans in order to eliminate double-counting.

The EPA has determined that, in the context of interactions among rate-based and mass-based plans, there is not explicit double-counting of the CO_2 emission reductions associated with counting measures located in mass-based states, considering the accounting methods outlined in this final rule. First, as discussed above, the accounting method for adjusting the CO_2 emission rate only counts the MWhs generated by a measure to adjust the MWh in the denominator of its reported CO_2 emission rate. The CO_2 emissions impacts of the measures will be reflected in the rate-based state only to the extent that the MWhs resulted in lower reported CO_2 emissions from an affected EGU in the rate-based state. To the extent that measures that provide substitute or avoided generation reduce generation from affected EGUs in a mass-based state, the effect of those measures is reflected in lower reported CO_2 emissions. The CO_2 emission reductions reflected in the rate and the mass state will necessarily be mutually exclusive, because both are based on reported stack emissions. Additionally, the mechanism in the mass-based state that is assuring CO_2 emission reductions is the mass goal or cap, which is met by affected sources adjusting their generation. Low- or zero-emitting MWhs from resources like RE and demand-side EE can serve load in the mass-based state and play a role in lowering compliance costs, but they play no direct role in mass-based compliance. As a result, no double-counting of emission reductions can take place.

Though there is no risk of double-counting emissions, some commenters expressed the concern that overall CO_2 emissions reductions would be eroded in situations where a source in a rate-based state counts the MWh from measures in a mass-based state, but the generation from that measure acts solely to serve load in the mass-based state. In that scenario, expected CO_2 emission reduction actions in the rate-based state are foregone as a result of counting MWh that resulted in CO_2 emission reductions in a mass-based state.

While the EPA understands this concern, we do not believe it is appropriate to restrict RE and demand-side EE crediting unilaterally between rate-based and mass-based states. Such a restriction could cut some states off from regional RE supplies that are assumed in BSER building block 3 and incorporated in the CO_2 emission performance rates or state rate-based CO_2 goals in the emission guidelines. Allowing crediting between rate- and mass-based states, as long as the risk of foregone CO_2 emission reduction actions in rate-based states are minimized, will assure a supply of eligible low- and zero-emitting MWhs that will further enable affected EGUs and states to meet obligations under the final rule. Therefore, the EPA has determined that it is appropriate for rate-based states to count MWhs from RE or demand-side EE measures, or similar low- or zero-emitting measures, located in mass-based states, subject to the condition that the measure must be implemented to meet electricity load in a state with a rate-based plan.[193] To assure that measures used to adjust a CO_2 emission rate meet this condition, the EPA is requiring that measures providing zero- or low-emitting generation from non-affected EGUs located in a mass-based state, such as RE, can only be counted if the electricity generated is delivered with the intention to meet load in a state with a rate-based plan and is treated as . This can be demonstrated through, for example: 1) the provision of a power delivery contract or power purchase agreement in which an entity in the rate-based state contracts for the supply of the MWhs in question and 2) documentation that the generation was treated as comparable to a generation resource used to serve regional load that included the rate-based state as part of planning and dispatch. The EPA is providing flexibility to states regarding the nature of the required demonstration, though the state must specify eligible demonstrations for approval in state plans.

Under an emission standards plan, this demonstration would be made by the provider of the measure seeking ERC issuance to the rate-based state. Under a state measures plan, the rate-based state will need to provide the demonstration of the eligibility of RE located in a mass-based state for ERC issuance as part of

[193] This does not need to necessarily be the state where the MWh of energy generation from the measure is used to adjust the CO_2 emission rate of an affected EGU.

its demonstration that it is meeting its CO_2 emission performance rates or achieving the state CO_2 emission goal for affected EGUs.

The following are examples of how requirements for a demonstration could be established in state plans and used to allow a resource in a mass-based state to be counted in a rate-based state. For an emissions standards state plan, a state could specify in the regulations for the rate-based emission standards included in its state plan that it will require a provider of RE that seeks the issuance of ERCs to show that entities in the rate-based state have contracted for the delivery of the RE generation that occurs in a mass-based state to meet load in a rate-based state. Under this approach, an RE provider in a mass-based state could submit as part of an eligibility application a delivery contract or power purchase agreement showing that the generation was procured by the utility, and were treated as a generation resource used to serve regional load that included the rate-based state. This documentation would be sufficient demonstration to allow the RE generating resource to meet the additional geographic eligibility requirement for generation of ERCs. All quantified and verified MWhs submitted for ERC issuance would need to be associated with that power purchase contract or agreement, and this fact would need to be demonstrated in the monitoring and verification reports submitted for issuance of ERCs.

Under a state measures rate-based plan, a state could require that any eligible MWhs that the state claims from a mass-based state are the result of contracted arrangements between entities in the rate-based state and providers in the mass-based state. If the state plan was approved by the EPA, such demonstrations would need to be submitted with the state's demonstration of how its state measures meet the CO_2 emission performance rates or achieve the state rate-based CO_2 emission goal for affected EGUs.

The ability for a rate-based state to count MWhs located in a mass-based state under the above conditions is limited to non-affected generating resources that are considered low- or zero-emitting, such as RE. This treatment does not apply to fossil-fuel fired EGUs, such as NGCC. If a mass-based emission limit has been applied to an affected EGU, there is no valid way to calculate whether it has MWh that are eligible for crediting, as is possible under a rate-based plan.

As stated earlier, commenters also expressed concern about the potential for a loss of emission reductions to occur given relative differences between states. These differences could include states' goals under either the rate- or mass-based approaches, or states' accounting of new sources. Commenters

These differences could induce increased generation in one state over another because the costs of compliance and relative costs of generation would vary between states. There was particular concern regarding how these differences would provide incentives for building new generation and expanding utilization of affected EGU generation in states that have less stringent goals, and that this movement of generation would result in increased emissions overall.

The EPA would like to confirm that

This could potentially result in the achievement of performance rates but with fewer overall CO_2 emissions reductions than projected nationally under the proposal.

In order to address these concerns, the EPA has determined final performance rates that serve to reduce relative differences between state goals, and thus the risk of leakage based upon those effects. In the proposal, goals differed significantly between states based upon individual assumptions included in the calculation. In the final rule, we are finalizing CO_2 emission performance rates for fossil fuel-fired electric utility steam generating units and stationary combustion turbines that are applied consistently across all affected EGUs. Additionally, these finalized performance rates were calculated regionally, further narrowing the differences across states. As the same sector performance rates are applied to all states, any differences stem from the relative prevalence of fossil fuel-fired electric utility steam generating units and stationary combustion turbines.

Commenters also suggested that the trading of emission credits across states under a rate-based approach would result in incentives to create credits, through the development of RE for example, in certain states with higher state goals. They noted that RE siting would thus not occur in the most optimal locations. The commenters assumed that zero-emitting credits are denominated in mass units by multiplying the number of MWh by some emission rate: either the state goal rate, the current state emission rate, a regional emission rate, or a calculated marginal rate. If those rates were higher in any states, zero-emitting MWhs would create more mass-denominated credits in those states, and thus RE and demand-side EE would be more valuable.

The incentive to target the location of zero-emitting generation or energy savings between states based on variation in its emission reduction value has been minimized by the nature of the accounting method finalized in this rule. As explained above on the general accounting approach and on the trading framework, we are adjusting rates using calculated MWhs, not based upon an emission reduction approximation as commenters outlined above. Not only does the method allow emission reductions to be accounted for as they occur across the grid, but it means the ERCs being traded across states represent one MWh of zero-emitting generation in whatever state it originated, and its value is unaffected by any emission rate associated with its state of origin. Thus, the finalized accounting and trading methods minimize the relative incentives for generating zero-emitting ERCs in a particular state based upon the rates that apply to that state.

Though all these aspects of the final rule can act to reduce the risk of leakage, there is still